ELECTRIC POWER RESEARCH INSTITUTE

Recommendations for an Effective Program to Control the Degradation of Buried Pipe

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REPORT SUMMARY

In May 2007, EPRI conducted a Nuclear Power Plants Piping Integrity Workshop in which the integrity of buried pipes was identified as one of the top priorities. In October 2007, EPRI conducted a follow-up Workshop on Buried Pipe attended by more than 40 representatives from utilities and EPRI. At the conclusion of the October 2007 meeting, the utility attendees unanimously recommended that EPRI sponsor the development of a recommendations document for buried pipe to help plant engineers prevent and mitigate degradation and leaks in buried pipes. This report has been prepared to address that need.

Background
Degradation of buried piping is a significant issue facing nuclear power plant owners. Unlike aboveground piping systems, buried pipes corrode and foul from the fluid side (inside diameter) and corrode or experience mechanical damage from the soil side (outside diameter). This continuing degradation is challenging to assess since the pipes are difficult to reach for inspection. When buried pipes leak, the source of leakage is difficult to locate, access, and repair in a timely manner. As a result, several plants have experienced costly leaks and repairs of their buried pipes.

The integrity of buried pipes has received increased interest from the Nuclear Regulatory Commission (NRC) via Inspection Procedure 62002 and license renewal reviews. The Institute of Nuclear Power Operations (INPO) has also included buried pipe integrity in several reviews. Finally, buried pipe integrity is of interest for new plants, to ensure that new designs build upon lessons learned from operation of current plants.

Although the mechanisms of corrosion are generally slow, they are cumulative. As plants age, buried systems experience more frequent leaks. As buried pipe coatings approach their end of life, they tend to disbond or become brittle, leaving more areas of the pipe directly exposed to the soil. Cathodic protection systems, where installed, also require more frequent checks and maintenance to ensure their continued adequacy.

Objectives
To provide a set of recommendations for nuclear power plants to use in implementing an effective program to detect and mitigate life-limiting degradation that may occur in buried piping systems.

Approach
Experience from the power industry as well as the experience and standards from other industries that have large quantities of buried pipe (such as waterworks, oil and gas transmission pipelines,

and process plants) and utilities engineers' reviews were used to develop the recommendations presented in this report.

Results

This document provides guidance and recommendations for a programmatic approach to help plant owners prioritize inspections of buried pipes, evaluate the inspection results, make run-or-repair decisions, select a repair technique, where required, and take preventive measures to reduce the likelihood and consequence of failures. The activities are organized in six elements:

- Develop a corporate program including training, implementing procedures, documentation, and performance indicators.
- Prioritize buried pipe systems and locations to be inspected based on risk of failure (likelihood and consequence of failure).
- Perform direct inspections to quantify the degree of degradation and damage.
- Evaluate the fitness-for-service of degraded buried pipes.
- Select the appropriate repair technique where required, including both non-welded and welded repairs.
- Take preventive actions to reduce the risk (likelihood and consequence) of future leaks or failures.

Two options for performing risk ranking of a given piping location (segment) can be used. The first option utilizes risk analysis, where the risk is equal to a quantified likelihood of the failure times the quantified consequences of the failure. The second option, detailed herein, places each piping location (segment) into a risk matrix based on a non-quantified likelihood of failure (for example, low, medium, and high) versus the non-quantified consequences of failure (for example, none, low, medium, and high). However, since both approaches require inspection of a prioritized sample of risk-ranked locations, it must be recognized that it will not be possible to prevent all leaks and failures of buried piping systems.

EPRI Perspective

Buried pipes in nuclear power plants are susceptible to degradation that can cause leaks and failures. Small leaks can be difficult to locate and all types of leaks can be expensive to repair due to accessibility issues. Some leaks also require that the plant be shut down in order to repair them. A broad-based and comprehensive program needs to be implemented at nuclear plants to reduce the probability and consequences of failure to an acceptable level. This report should be viewed as a living document that is subject to periodic revision as further data, application experience, and technology become available.

Keywords

Buried Pipe
Corrosion
Cathodic Protection
Risk Ranking
Nondestructive Examination
Piping Repair

ABSTRACT

This document contains guidance and a series of recommendations for an effective program to control the degradation of buried piping systems. The recommendations are based on the experience accumulated in the power industry as well as the large body of knowledge in buried pipe integrity from the waterworks, process and oil and gas pipeline industries. For ease of implementation, the guidance and recommendations have been organized into a program consisting of six elements: (1) Procedures and oversight, (2) Risk ranking, (3) Inspections, (4) Fitness-for-service, (5) Repairs, (6) Prevention and mitigation.

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PROCEDURES AND OVERSIGHT

1.1 Background

1.1.1 Industry Need

In May 2007, EPRI conducted a Nuclear Power Plants Piping Integrity Workshop in which integrity of buried pipe was identified as one of the top priorities (reference 1). In October 2007, EPRI conducted a follow-up Workshop on Buried Pipe, which was attended by over forty representatives from utilities and EPRI. At the conclusion of the October 2007 meeting, the utility attendees unanimously recommended that EPRI sponsor the development of a recommendations document for buried pipe to assist plant engineers in preventing and mitigating degradation and leaks in buried pipes (reference 1).

This report, *Recommendations for an Effective Program to Control the Degradation of Buried Pipe*, has been prepared to address this need. The program is presented in six elements, with guidance and recommendations presented for each element. In addition, the recommendations from each step have been grouped and listed in Appendix A.

1.1.2 Regulatory and Industry Context

In addition to the immediate safety and financial needs to prevent and mitigate leaks from buried pipes, the buried pipe integrity program is also to be viewed in the context of the Nuclear Regulatory Commission's (NRC) rules on aging management:

- 10 CFR 50.65, Maintenance Rule (reference 2).
- 10 CFR Part 54, License Renewal Rule (reference 3).

Other regulatory publications specifically addressing issues related to buried pipes are:

- NUREG-1801, Generic Aging Lessons Learned (GALL) Report (reference 4).
- NRC Inspection Manual 62002, Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants (reference 5).
- NUREG/CR-6679, Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants (reference 6).
- NUREG/CR-6876, Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants (reference 7).

The Institute of Nuclear Plant Operations (INPO) and the World Association of Nuclear Operators (WANO) have also addressed the integrity of buried piping systems in several of their documents. Additionally, the Nuclear Energy Institute has initiated the Ground Water Protection Initiative, NEI 07-07 (reference 16).

1.1.3 Challenges

Buried pipes present many challenges:

- Buried pipes are not readily accessible for inspection and leak detection.
- Buried pipes are subject to degradation mechanisms from the outside (soil side) as well as from the inside (fluid side).
- The external environment of buried piping has chemical, geotechnical and civil-structural considerations that can be unique to each installation and/or site.
- Pipe embedment materials can also vary by their nature and degree of inspection or verification during the installation process.
- Buried pipes encompass a variety of services such as water, gases, fire protection, fuel oil and lube oil.
- Buried pipes may contain radioactive fluids.
- Buried pipes encompass a wide range of materials: steel, cast iron, copper alloys, concrete, asbestos, PVC, polyethylene, etc.
- Buried pipes encompass a wide range of sizes, from over 10 ft diameter down to small bore piping (2 in and smaller).
- Buried pipes may be bare or they may have a variety of external coatings and internal linings.
- Buried pipes may or may not be cathodically protected.
- Because the pipes are not readily accessible, buried pipe inspections may not have been as common as aboveground pipe inspections.
- The design formulas and corresponding design margins for soil and surface loads are not defined in either the ASME Section III (reference 12), ASME B31.1, ASME B31.7 (reference 13), or the National Fire Protection Association (NFPA) (reference 118) Codes.

1.1.4 Prior Work

This document builds upon a body of work, publications, codes and standards across industries: oil and gas pipelines, waterworks, process plants, and power plants. These practices and methods from across industries are reflected in this guide, and adapted to nuclear plant applications. Appendix B provides a bibliography of relevant standards and publications.

1.2 Purpose and Scope of the Recommendations

1.2.1 Purpose

This report provides methods and recommendations to develop a sound and effective program to achieve safe and reliable operation of buried piping systems in nuclear power plants.

The intent of this document is to provide comprehensive yet succinct guidance in order to facilitate its practical implementation. The document identifies the data necessary for developing a safe and cost-effective Buried Pipe Integrity Program, in many cases in the form of checklists and tables, with applicable references for further details.

1.2.2 Scope

The recommendations apply to the following buried piping systems:

- Both safety-related and non-safety-related piping systems.
- Piping designed to the ASME B31.1, B31.7, Section III, NFPA and AWWA piping Codes.
- Metallic pipe (ferrous and non-ferrous). Additional materials may be added at a later date.
- Systems conveying a variety of fluids: (1) Liquids (water supply and return, fuel and lube oil, etc.), (2) Gases (off-gas, air, vacuum, hydrogen, argon, helium, oxygen, nitrogen, etc.), and (3) Vapors (steam)

The recommendations apply to both internal diameter (ID) and external diameter (OD) corrosion. If ID corrosion has been addressed through other appropriate programs such as EPRI's Service Water Piping Guidelines (reference 14), then ID corrosion may be either:

- Excluded from this program, in which case this program would be limited to OD corrosion, or
- The results of the existing ID corrosion assessment program may be combined with the OD corrosion assessment from this program.

This document does not apply to other types of buried commodities such as vessels, tanks, conduits, and intake structures.

1.3 Organization of the Recommendations

These recommendations are provided as a six-step process, as illustrated in Figure 1-1. Other organizations have identified a different number of steps. For example, NACE Recommended Practice 0502 (reference 15) provides a four-step approach, also illustrated in Figure 1-1. Each step recommended herein includes a diagram of the recommended sub-steps and options:

- Step 1 (Chapter 1), after a description of the background, scope, purpose and organization of the guide, this Chapter addresses the need for a program policy, performance indicators and technical procedures.

- Step 2 (Chapter 2) addresses the risk ranking process to help prioritize the buried pipe systems and locations to be inspected on the basis of likelihood and consequence of failure. This Step includes indirect inspection techniques for assigning likelihood of failure.
- Step 3 (Chapter 3) describes the direct inspections used to measure the extent of degradation and damage.
- Step 4 (Chapter 4) identifies and describes the methods available to evaluate fitness-for-service of buried pipes and make run-or-repair decisions.
- Step 5 (Chapter 5) describes and provides references for repair options. They include both non-welded and welded repairs.
- Step 6 (Chapter 6) describes preventive actions to reduce the risk (likelihood and consequence) of future leaks or failures.
- Chapter 7 is the list of references.

Each of the six steps contains recommendations in their proper context.

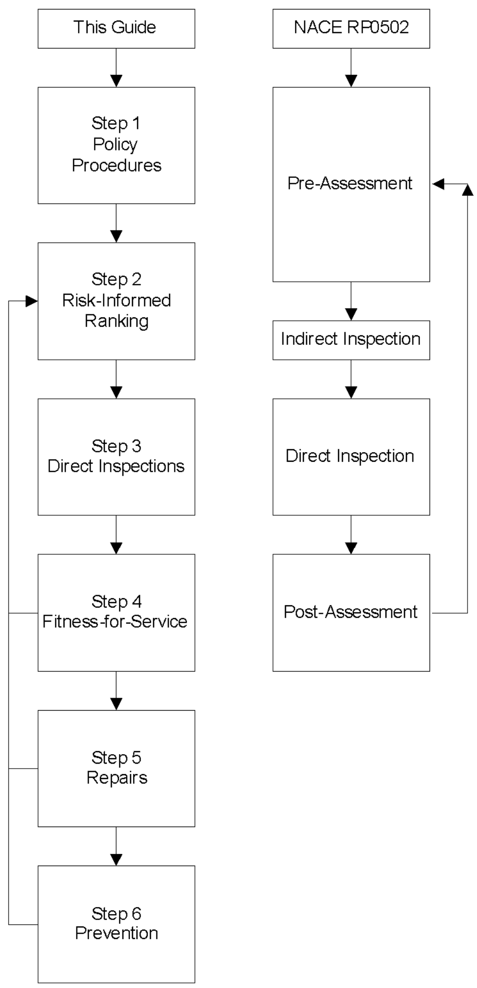

Figure 1-1
Buried Pipe Integrity Program Diagram

Appendix A compiles a list of all the recommendations.

Appendix B provides a bibliography on the topic of buried pipe integrity.

Appendix C provides a list of piping systems that often have one or more buried segments.

Appendix D describes soil sampling that is recommended as part of indirect inspections.

Appendix E describes various methods for performing over-the-line surveys.

Appendix F presents a list of cautions and procedures that should be applied when excavating or entering buried pipe.

Appendix G describes various methods that may be used for direct inspections of buried piping.

Appendix H describes two options for corrosion monitoring.

Appendix I summarizes methods to assess the fitness-for-service of degraded pipe.

Appendix J describes leak detection and isolation methods.

Appendix K describes methods that may be used to repair degraded piping

Appendix L describes strategies for prevention and mitigation of corrosion in buried piping.

1.4 Procedures and Performance

Recommendation Procedures-1, Procedures and Oversight: A Buried Pipe Integrity Program Plan and implementing procedures should be developed.

Figure 1-2 outlines the procedures and performance indicators addressed in this Chapter.

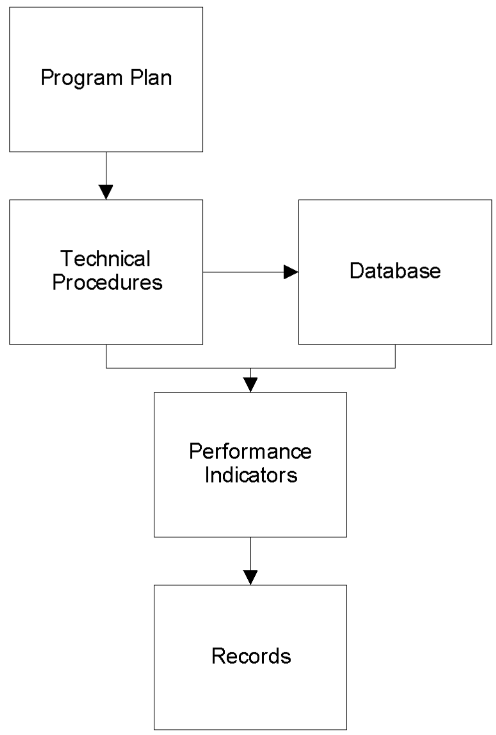

Figure 1-2
Procedures and Performance Indicators

Policies and procedures should address the following.

1.4.1 Program Plan

A Program Plan should be developed for buried piping. The plan should include the following elements:

- Management's objectives for safe and reliable operation of buried pipe systems.
- Interface with other inspection and integrity programs such as the Nuclear Energy Institute's (NEI) Ground Water Initiative 07-07 (reference 16).
- A commitment to a well structured process: line selection, risk ranking, inspection, fitness-for-service assessment, repairs, failure prevention and mitigation, and feedback and tracking.
- Roles and responsibilities defined, including program manager, inspection organization, engineering organization for risk ranking and fitness for service evaluations, organizations for modifications, repairs and preventive maintenance..
- Training.
- A schedule for the completion of a baseline assessment.
- A commitment for continued implementation.
- Reporting and trending.

- Feedback and continuous improvement.
- System or program health report and the corresponding performance indicators.
- Financial commitments (budget) for all program elements.

1.4.2 Technical Procedures

Implementing procedures should address:

- Risk ranking process and methods (Chapter 2).
- Inspection techniques, implementation of inspections, scope expansion, interface to fitness-for-service assessment and trending, storage and retrieval of results (Chapter 3).
- Fitness-for-service calculation methods and margins (Chapter 4).
- Repair options (Chapter 5).
- Prevention methods, rehabilitation and leak detection techniques (Chapter 6).

1.4.3 Database

Recommendation Procedures-2, Program Database: A database should be developed to track key program data and performance indicators.

Key program data to be stored and tracked in the database should include:

- System and segment data, including for example (as applicable), but not limited to system description / designator, segment identification, drawing / specification references, design code, design pressure, design temperature, process fluid, tritium concentration, pipe sizes, joint configuration (welded, flanged, bell and spigot), soil cover depth, piping material, embedment material, backfill material, pipe lining material, pipe coating material, cathodic protection, Nuclear Safety Classification, Aging Management Program Applicability, Maintenance Rule Applicability (10CFR50.65).
- Risk ranking and basis for inspection decisions.
- Inspection schedule.
- Inspection results.
- Results of indirect inspections
- Results of direct inspections
- Analysis of results and basis for run-or-repair decisions.
- Trends and recommendations for future inspections.
- Results of leak detection surveys.
- Leak history.

- Repair and replacement history.
- System or program health report performance indicators.

1.4.4 Performance Indicators

Recommendation Procedures-3, Performance Indicators: System or program health reports and performance indicators should be developed for the Buried Pipe Integrity Program. The performance indicators should be tracked periodically and reported to management.

The performance indicators may include:

- Program Plan and Technical Procedures are in-place, current, and being implemented (Step 1).
- Program documentation is complete and current (Step 1).
- Roles and responsibilities defined, accepted and owned by organizations / individuals for inspection, engineering, maintenance and modifications.(Step 1)
- The Program Manager and backup are identified and trained.
- Program resources are adequate.
- The Program has been recently benchmarked (Step 1).
- Information about buried lines has been collected (Step 2).
- Risk ranking analysis has been performed and is current (Step 2).
- The database is complete and current (Steps 1 and 2).
- Indirect inspections are current (Step 2).
- Soil analysis has been performed at representative locations (Step 2).
- Direct inspections of identified locations have been performed (Step 3).
- Number of deferred inspections (Steps 2 and 3).
- Number of locations found to be below Code required minimum design thickness where the fitness-for-service assessment was required (Step 4).
- Number of deferred repairs (Step 5).
- The cathodic protection system is functional and parameters are within specified limits (Step 6).
- The program self-assessments have been performed and are current.
- Number of open findings or Areas of Improvement from external audits or assessments (INPO, NRC).
- Number of open findings from self-assessments.
- Number of significant leaks or failures last cycle.

1.4.5 Other Program Documentation

The program plan, technical procedures, database, inspection results, performance indicators and major decisions should be documented, and appropriate records should be maintained.

2
RISK RANKING

The second step of the Buried Pipe Integrity Program is to rank the buried pipe segments on the basis of risk. Risk is the combination of likelihood of failure and consequence of failure. One approach for risk ranking of buried pipe segments is presented in this Chapter. This step consists of sub-steps illustrated in Figure 2-1.

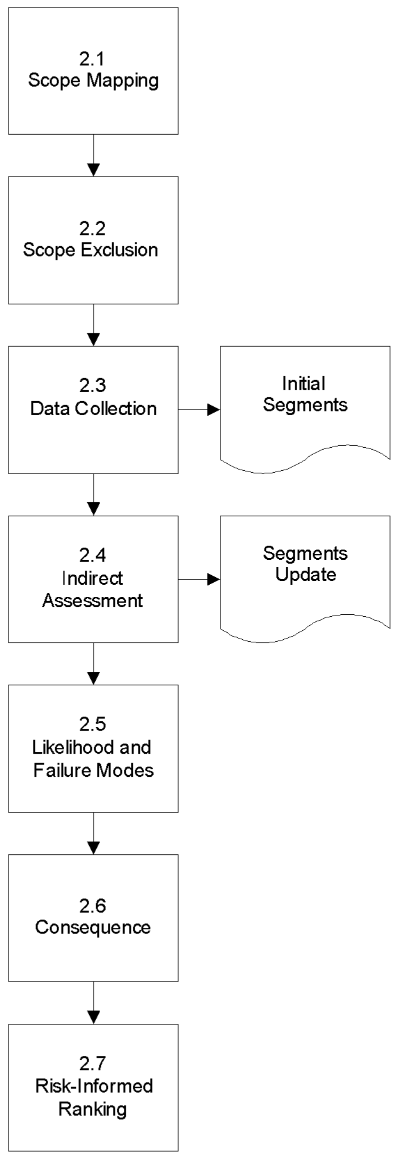

Figure 2-1
Risk Ranking

2.1 Scope Mapping

***Recommendation Risk-1, Scope Drawings*:** A set of as-built drawings should be assembled, showing the route of buried pipes, including their location relative to other buried and aboveground buildings, structures and commodities.

- The scope of buried piping should be documented on existing Piping and Instrument Diagrams (P&IDs), isometric or orthographic drawings. Consideration should be given to generating as-built isometrics for buried lines that are in the scope of the program. The scope drawings should be cross-referenced to the database information.

Note that original construction photographs are quite useful to view the pipe layout before burial.

Recommendation Risk-2, Route Confirmation: The buried pipe routes and adjacent buried commodities should be confirmed through field surveys.

Field inspection techniques to locate buried pipe include ground penetrating radar (GPR) and AC current attenuation (ACCA). A description of ACCA is provided in Appendix E.

2.2 Scope Exclusion

Recommendation Risk-3, Scope Exclusions: Buried piping segments whose failure is inconsequential, and would cause no direct or collateral damage (as described under Section 2.6 Consequence Assessment), may be excluded from the scope of the buried piping integrity program.

- Scope exclusions should be documented and approved by engineering and operations, and should consider the following:
- The consequence should consider that each of the four failure modes (leakage, break, mechanical damage and occlusions, as described in Section 2.5) is "Highly Likely."
- The nuclear safety, radiological safety, industrial safety, environmental, continued unit operation, collateral damage and / or economic consequences of a failure should be "None" or "Low".

2.3 Data Collection

Recommendation Risk-4, Data Collection: Line-specific data should be collected and compiled for use in risk ranking, inspection planning and fitness-for-service assessment. The line should be subdivided into segments of similar characteristics.

2.3.1 Data Collection from Records

- Data to be collected from plant records for use in the risk ranking is listed in Tables 2-1 through 2-3. The data should be collected for the entire line (buried pipe of a same system), and will be used to subdivide the line into segments (parts of a line) of similar characteristics, similar likelihood of failure, and similar consequences of failure.

Table 2-1
Important Variables to Assess the Likelihood of an OD Initiated Leak or Break

Variable
What is the pipe material?
What is the pipe nominal diameter?
What is the nominal wall thickness?
What are the operating and design pressures?
What are the operating and design temperatures?
What is the code required minimum wall thickness?
What was the installation date?
What are the type of joints?
What is the yield stress and Code allowable stress at operating temperature?
Is there a history of leaks in the line?
Is there a history of breaks in the line?
Has the segment been repaired?
Date of segment repair
Is there a known degraded condition and to what extent?
What type and thickness of coating was used?
Are there any unmitigated heavy surface loads?
Is there a history of ground settlement?
Is there a history of building settlement?
What is the segment burial depth?
Is the segment buried above the frost line?
What is the trench fill material?
What is the resistivity in the trench fill material (seasonal range)?
What is the redox potential in the trench fill material (seasonal range)?
What is the moisture content in the trench fill material (seasonal range)?

Table 2-1 (continued)
Important Variables to Assess the Likelihood of an OD Initiated Leak or Break

Variable
What is the pH of the trench fill material (seasonal range)?
What is the chloride concentration in the trench fill material (seasonal range)?
What is the sulfide concentration in the trench fill material (seasonal range)?
What type of cathodic protection is used?
Has the cathodic protection been used continuously?
What is the inspection interval for the cathodic protection system?
Is the cathodic protection system operating within prescribed limits?
What is the cathodic protection ground survey interval?
What is the condition of the coating?
What is the coating survey interval?
What was the measured thickness at last inspection?
What was the date of the most recent inspection?

Table 2-2
Important Variables to Assess the Likelihood of an ID Initiated Leak or Break

Variable
What is the pipe material?
What is the pipe nominal diameter?
What is the nominal wall thickness?
What are the operating and design pressures?
What are the operating and design temperatures?
What is the code required minimum wall thickness?
What was the installation date?
Is there a history of leaks in the line?
What are the type of joints?
Are there backing rings?
Was there post-weld heat treatment?
What is the yield stress and Code allowable stress at operating temperature?
Is there a history of breaks in the line?
Has the segment been repaired?
Date of segment repair
Is there a known degraded condition and to what extent?
What type of lining was used?
What is the operating flow velocity?
Is there a potential for cavitation?
Is there a history of tuberculation (water-filled line)?
Is there a history of bi-valves (water-filled line)?
Does the water source contain bi-valves (water-filled line)?
What is the water pH (water-filled line)?
What is the concentration of sulfides (water-filled line)?
What is the concentration of sulfates (water-filled line)?
What is the concentration of chlorides (water-filled line)?
What is the concentration of Total Organic Carbons (water-filled line)?
What is the Ryznar Scaling Index (water-filled line)?
What type of biocide is used (water-filled line)?
What is the biocide concentration?
Is the biocide injected upstream of the segment (water-filled line)?

Table 2-2 (continued)
Important Variables to Assess the Likelihood of an ID Initiated Leak or Break

Variable
What was the measured thickness at last inspection?
What was the date of the most recent inspection?
What is the condition of the lining?
When was the lining last inspected?

Table 2-3
Important Variables for Assessing the Consequences of a Leak or Break

Variable
Nuclear safety classification
Code classification
Line content for potential ground contamination
Could flow from a leak be made-up without shutting down the unit?
Could flow from a break be made-up without shutting down the unit?
Does the line have a leak detection system?
What would be the cost to repair a leak or break?
Would a failure cause collateral damage (nearby buildings, conduit, water intrusion into underground electrical pullboxes or manholes, etc)?
Would a failure affect nuclear safety or core damage frequency?
Does the line service more than 1 unit?
Would a failure affect worker safety?
Would a failure result in radioactive ground contamination?
Would a failure result in non-radioactive ground contamination?
Would a failure result in airborne contamination?
Would leakage be reportable to local, state or federal authorities?
Would a failure cause loss of generation? If so, for how long?
Would loss of flow area due to occlusion be acceptable?
Are contingency measures in place to mitigate consequences of the potential leak?
Would failure result in entry into a Tech Spec LCO?
Would failure result in an operator work around or long term temporary modification?

2.3.2 Identification of Lines and Segments for Risk Ranking

Based on the data collected from records, the buried pipe should be subdivided into a series of segments. The piping in each segment should have similar characteristics resulting in similar likelihood and consequences of failure. A new segment should be started where there is a change to the likelihood or consequences variables identified in Tables 2-1 through 2-3. This segmentation will guide the selection of areas for indirect inspections, and should be updated as data continues to be gathered in later inspections.

2.4 Indirect Inspections

Indirect inspections are survey techniques that help assess the likelihood of degradation or damage without direct access to the pipe wall for a direct measurement of the wall condition.

2.4.1 Soil-Side Indirect Inspections

The parameters to be collected and measured are listed in Table 2-1. The indirect inspection methods consist of soil analysis and over-the-line surveys.

2.4.1.1 Soil Analysis

Recommendation Risk-5, Soil Analysis: Soil analysis data should be collected to help assess the likelihood of OD corrosion.

The following locations should be considered for soil analysis using either in-situ or laboratory analytical methods. The sampling should be performed as close as practical to the pipe (e.g., in the burial trench). Illustrations are provided in Appendix D.

- A representative sample of locations near the pipe, with known burial conditions, to confirm that they are as documented and to estimate the soil corrosivity. Discrepancies between the sampled soil and soil records should be investigated.
- Segments identified as high likelihood of failure, based on the previous leaks or failures.
- Locations of unknown burial conditions.
- Changes in type of soil (fill or native) in contact with the pipe.
- Locations where burial conditions are suspected to have changed (such as salts or contaminants leaching into the soil, runoff, ground water intrusion, etc.).
- Soil analysis should be conducted from samples collected during various seasons to gather the range of soil parameters.

2.4.1.2 Checks of the Cathodic Protection System

Recommendation Risk-6, CP Check: Where buried pipes are protected by a cathodic protection (CP) system, the CP system should be periodically inspected and tested to assess its continued adequacy.

The CP system should be monitored from test stations to assess its adequacy and effectiveness. Management of the CP system may be implemented under a separate program, and data provided to the buried pipe program. Recommended locations for test stations include (references 22, 24 through 26, 102):

- Rectifier stations.
- Cased pipe installations.
- Metallic foreign pipeline crossings.
- Insulating joints.
- Valve stations.
- Sacrificial anode installations.
- Road crossings.
- Stray current areas.

The CP system will fall into disrepair if not properly maintained, and will not protect the buried pipe. The CP system check should consider the recommendations of NACE SP0169 (reference 22).

- Sources of impressed current should be checked every two months, unless justified otherwise. Checks should include: current output, power consumption, rectifier “on” status, cleanliness of rectifier and ventilation screen, electrical connections at rectifiers, oil (for oil immersed units), and current control devices.
- Protective devices should be checked every two months, unless justified otherwise. Checks should include: reverse-current switches, diodes, interference bonds, and other protective devices, whose failures would jeopardize pipeline protection.
- Periodic checks should verify satisfactory cathodic potential on the pipe and groundbeds.
- Impressed current protective facilities should be inspected annually, unless justified otherwise, by a NACE CP tester or equivalent. Inspections should include: a check for electrical malfunctions, safety ground connections, meter accuracy, circuit resistance, pipe-to-soil potential, on-off potential, stray currents, and effectiveness of dielectric insulating kits.
- Caution: Foreign pipelines or stray currents can be the source of stray current corrosion, can decrease CP effectiveness, and can make CP system assessments much more difficult. These types of crossings will require greater expertise in interpretation of results.

The CP checks are typically coupled with an over-the-line survey, such as a Close Interval Potential Survey (CIPS) or Direct Current Voltage Gradient (DCVG).

The effectiveness of the CP system can also be measured using CP coupons installed near the pipe, receiving the same CP current as the pipe. The coupon is typically mounted in a plastic pipe and connected to the pipe CP circuit through an on/off switch. Coupon potentials are measured by lowering a reference electrode inside the plastic pipe (reference 26).

2.4.1.3 Over-the-Line Surveys – CP Protected Lines

Recommendation Risk-7, Over-the-Line Surveys: It is recommended that over-the-line surveys be conducted as part of Step-2, Risk Ranking, to help assess the likelihood of OD corrosion. The surveys should be conducted periodically and the likelihood of corrosion should be updated accordingly.

Over-the-line survey methods include:

- Pipe-to-Soil Potential.
- Direct Current Voltage Gradient (DCVG).
- Pearson Survey.
- AC Current Attenuation (ACCA) Survey.
- Close Interval Potential Survey (CIPS).

Descriptions of the methods are provided in Appendix E.

It is recommended that over-the-line surveys of CP protected lines be conducted once every three years initially, then the frequency of surveys can be adjusted based on results.

2.4.1.4 Over-the-Line Surveys – Non-Cathodically Protected Lines

Over-the-line surveys should also be performed for lines that are not cathodically protected to provide information on the health of the coating. Acceptable methods include:

- Direct Current Voltage Gradient (DCVG).
- Pearson Survey.
- AC Current Attenuation (ACCA) Survey.

Descriptions of the methods are provided in Appendix E.

It is recommended that over-the-line surveys of non-cathodically protected lines be conducted once every three years initially, then the frequency of surveys can be adjusted based on results.

2.4.2 Fluid-Side (ID) Indirect Inspections

Recommendation Risk-8, ID Corrosion Assessment: The potential for fluid-side corrosion and fouling of buried pipe should be evaluated to determine the likelihood of failure.

The parameters to be collected and measured are listed in Table 2-2.

2.5 Likelihood Assessment and Failure Modes

Recommendation Risk-9, Likelihood of Failure: The likelihood of failure (e.g., low, medium, high) should be determined for each segment of the buried pipe system for each failure mode.

A minimum of three-levels of likelihood is recommended (Low, Medium and High) consistent with ASME Code Case N-560-2 (reference 35). Note that a larger number of likelihood categories may be adopted. For example, risk-based ranking used in refineries and petrochemical plants generally follows API 580 (reference 36) and API 581 (reference 37) which uses a scale of five likelihood levels.

2.5.1 Failure Modes

Failure refers to a loss of fluid (leak or break) or a reduction in flow area. The likelihood as well as the consequence of failure is a function of the failure mode: leak, break, mechanical damage, or occlusions. For this reason it is necessary to evaluate the likelihood and consequence of each failure mode separately:

- Leak: A leak is caused by a pinhole puncture or a tight crack, without burst or fracture (Figures 2-2 and 2-3).
- Break: A break may consist of a burst, a guillotine break or a brittle fracture. A burst is a rupture caused by over-pressure, either by a steady pressure rise or by a sudden pressure transient (waterhammer), with or without corrosion (Figures 2-4 and 2-5). A guillotine break in a buried pipe may be due to soil movement (Figures 2-6 and 2-7). A brittle fracture may be due to overload of a pipe made of brittle material such as cast iron (Figure 2-8), or a material susceptible to selective leaching (e. g., cast iron, brass alloys).
- Occlusions: This failure mode groups the mechanisms that cause a reduction in flow area from the growth of macro or micro fouling (algae, mussels (Figure 2-9), etc.), deposition of debris, as well as damage caused by loosened deposits carried downstream.
- Mechanical damage: Mechanical damage is caused by a large accidental impact or movement of the pipe, and can take the form of a dent (deformed cross section), a gouge (cut), a puncture, or a buckle.

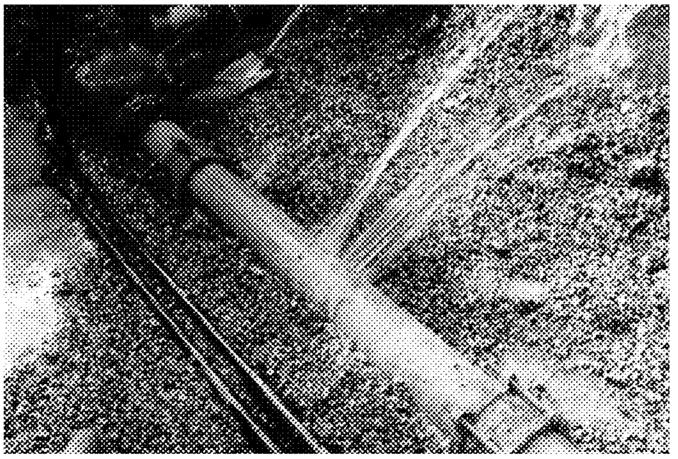

Figure 2-2
Leaks in Buried Pipe

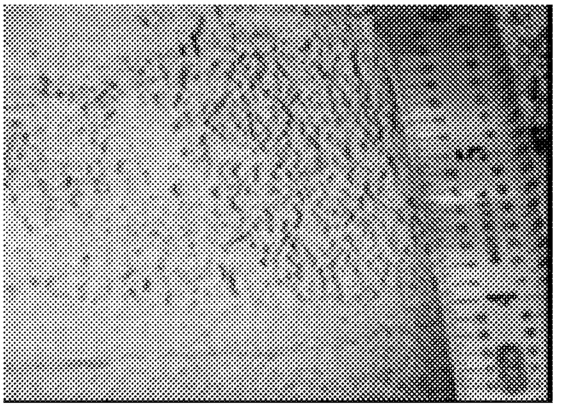

Figure 2-3
Tight Cracks

Figure 2-4
Burst of Corroded Pipe

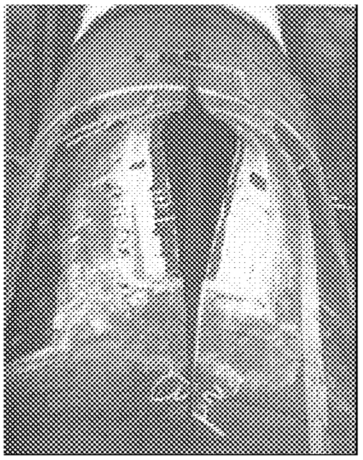

Figure 2-5
Over-Pressure Burst

Figure 2-6
Landslide-Induced Fracture

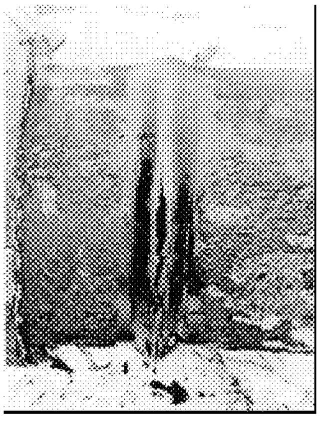

Figure 2-7
Crack at Pipe Buckle

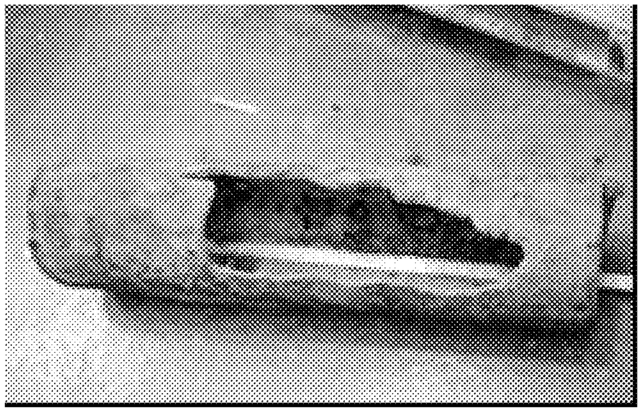

Figure 2-8
Fracture of Cast Iron Pipe

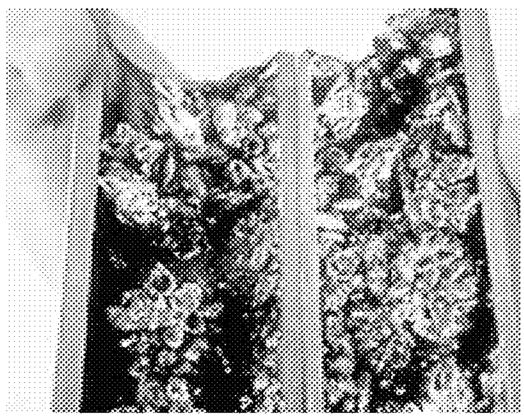

Figure 2-9
Macrofouling Reduces Flow Area

2.5.2 Likelihood of Leak

2.5.2.1 Likelihood of OD-Induced Leak

The likelihood of an OD-induced leak should consider pitting induced from the soil side, environmentally assisted cracking, and other degradation mechanisms that may be present. The parameters that should be considered in this assessment are identified in Table 2-1. They include (references 31-33):

- Pipe material, coating, and condition of coating.
- Cathodic protection, including its existence, operation, maintenance, and history.
- Soil parameters.
- Wall thickness, Code required minimum wall thickness, operating conditions.
- Leak history.

2.5.2.2 Likelihood of ID-Induced Leak

The likelihood of ID-induced leak should consider pitting related to microbiologically influenced corrosion (MIC), pitting related to factors other than MIC (e.g., sulfides), environmentally-assisted cracking, and other degradation mechanisms that may be present, unless internal corrosion has been assessed in a separate program. The parameters that should be considered in this assessment are identified in Table 2-2 and include:

- Pipe material, joints, lining, and condition of lining, if known.
- Water parameters and water treatment.
- Line operation.
- Wall thickness, Code required minimum wall thickness, operating conditions.
- Leak history.

If the likelihood of ID-induced leak is not addressed as part of the buried pipe program, options include:

- For service water piping, the EPRI Service Water Piping Guidelines (reference 14) can be used to establish the likelihood of ID water-side corrosion.
- For fluids other than water (oil, gases, etc.), the risk of ID corrosion should be assessed based on a system-specific corrosion assessment.

2.5.3 Likelihood of Break

The likelihood of break should be assessed based on normal operating conditions and the consideration of design-basis overloads.

The prediction of break may be achieved by one of three methods, as described below: (1) quantitative assessment using leak-before-break analysis, (2) bounding assessment using ASME Code Case N-560-2 (reference 35) analysis, or (3) qualitative assessment.

2.5.3.1 Leak-Before-Break

Stress and fracture mechanics analyses can be used to predict whether a degraded pipe will leak before it breaks (LBB), as described in Chapter 4, Fitness-for-Service.

2.5.3.2 Code Case N-560-2

The risk-informed inspection method of ASME Code Case N-560-2 (reference 35) makes the bounding assumption that "The consequence analysis shall be performed assuming a large break for most segments. The exceptions are piping for which a smaller leak can be justified through a leak-before-break analysis in accordance with the criteria specified in NUREG-1061, Volume 3, and 10CFR50, Appendix A, General Design Criteria 4."

2.5.3.3 Qualitative Assessment

A burst may be considered to have a low likelihood if all the following conditions are met:

- The system is moderate energy (temperature below 200°F (93°C) and pressure below 275 psi (1.9 MPa) during normal operation) (reference 38).
- The material is ductile (ASTM material specification with an elongation at rupture over 15% or Charpy toughness over 20 ft-lb (27 Joules) at the minimum operating temperature).
- There is no risk of dynamic pressure transient (waterhammer) in the line.
- There is no risk of heating of trapped liquid.
- The service is not a flashing liquid (refrigerant, pumped condensate above 212°F (100°C), etc.).

A break may be considered to have a low likelihood if all the following conditions are met:

- The material is ductile (the material specification requires an elongation at rupture of 15% or more or the material has a Charpy toughness over 20 ft-lb at the operating temperature).
- There is no evidence of significant ground settlement and no risk of landslide.
- There are no unanalyzed heavy traffic loads over the pipe.

If all of the above conditions are not met, the likelihood of break should also consider the additional damage that may have been caused by pitting, environmentally assisted cracking, and other degradation mechanisms that may be present.

2.5.4 Likelihood of Mechanical Damage

The likelihood of mechanical damage should be assessed based on the potential for large external forces. Mechanical damage (dent, gouge, buckling) may be considered of low likelihood if all the following conditions are met:

- There is no evidence of significant ground settlement, loss of backfill, or landslide.
- There is no risk of third-party damage (surface traffic or excavation impact).

2.5.5 Likelihood of Occlusions

The likelihood of flow constriction due to occlusions, and the potential for damage from loose deposits and debris should be assessed. Flow constriction is likely in water lines with stagnant, intermittent, or low flow rate, and with a potential for (references 14, 34):

- Growth of macro-organisms such as European Zebra and Quagga mussels in flowing channels, Asiatic clam in stagnant areas, and barnacles, blue mussels, oysters, jellyfish, seaweeds, etc.
- Growth of micro-organisms: The accumulation of gel-like secretions from bacteria, which can in turn collect silt and corrosion products.

- Solids Deposition: The deposition or entrapment of solids suspended in the water.

2.6 Consequence Assessment

Recommendation Risk-10, Consequence of Failure: A consequence of failure should be determined for each segment and each failure mode.

The consequence of failure of a buried pipe should address Environmental, Safety and Health (ES&H) consequences and costs. The parameters that should be considered in the consequence assessment are outlined in Table 2-3 and include the following:

- The failure mode (leak, break, occlusions, mechanical damage).
- The ability to detect the failure (leak or break) or degradation in a timely manner.
- The ability to isolate or by-pass the failure.
- The consequence in terms of safety, environmental damage and costs.
- Direct damage to the buried pipe and collateral damage to nearby structures and components.

2.6.1 Environmental, Safety and Health Consequences

2.6.1.1 Nuclear Safety

- Nuclear safety.
- Core damage.

2.6.1.2 Radiological Impact

- Tritium release.
- Contamination.

2.6.1.3 Industrial Safety

- Worker safety.
- Ground failure, landslide.
- Collateral damage to buildings and structures.
- OSHA regulations.

2.6.1.4 Environmental Damage

- Soil contamination.
- Ground water contamination.

- Contamination of other systems and ponds.
- Air contamination.

2.6.1.5 Cost Consequences and Financial Losses

- Production loss (shutdown, 72-hour LCO, power reduction, etc.).
- Line services more than 1 unit.
- Accident investigation.
- Retrofits to prevent recurrence (materials, linings and coatings, chemistry controls, protective measures such as cathodic protection, change in design practices, fabrication, inspections, operations).
- Pipe repairs.
- Repair of indirect damage (ground collapse, sink hole, electrical short, damage to other buried utilities, etc.).
- Nuclear insurance, liability.
- Impact on license extension (generic aging lessons learned GALL).

2.7 Risk Ranking

Recommendation Risk-11, Risk Ranking: Following the determination of likelihood and consequence of failure for each segment and each failure mode, a risk rank should be determined for each segment in order to prioritize inspections or other failure prevention measures.

Risk ranking may be achieved by using either risk analysis or development of a risk matrix.

2.7.1 Risk Analysis

Risk analysis assigns point values to the likelihood and consequence parameters, and establishes a risk ranking for each piping segment that is a function of the likelihood of failure and the consequence of failure.

If Risk Analysis is used, it should be capable of considering the following:

- The risk associated with each of the types of failure identified in Section 2.5.
- The risk associated with OD (soil-side) or ID (fluid-side) induced failures should consider the variables identified in Tables 2-1 and 2-2.
- The consequences of failure should consider the parameters identified in Section 2.6.
- Segments should be ranked based on their total risk.

2.7.2 Risk Matrix

A Risk Matrix is a matrix of likelihood of failure vs. consequence of failure. In practice, 3x3 to 6x6 matrices have been used in the power and process industries. Figure 2-10 is an example of a 3x4 risk matrix, based on ASME Code Case N-560-2 (reference 35).

	No Consequence	Low Consequence	Medium Consequence	High Consequence
High Likelihood				
Medium Likelihood				
Low Likelihood				

Figure 2-10
Example of a 3x4 Risk Matrix

2.7.3 Software to Automate Risk Ranking

Computer software can be used to automate the risk ranking described in this section. If used, the following attributes should be included unless justified otherwise:

- Separately consider ID-initiated and OD-initiated corrosion.
- Separately consider the risks of leak, break, and occlusion; and be able to identify the overall governing risk to each segment.
- Consider all causes of leaks and breaks.
- Take into account the pertinent variables identified in Tables 2-1, 2-2 and 2-3.

An example of such software is EPRI's BPWORKS (reference 119).

2.8 Selection of Inspection Locations

Inspection locations for buried piping should be selected considering the following:

- Results of the risk ranking (e.g., sequence in the risk analysis or location in the risk matrix).
- Plant experience.
- Industry experience. These include:
  - Locations where the pipe enters or exits the soil (differential aeration).

  - Locations where dissimilar metals are in contact without use of insulating kits (galvanic corrosion).
  - Locations where the pipe enters or exits water (water line corrosion).
  - Locations where the pipe enters or exits a structure (structures disperse cathodic protection currents).
- Trending of past inspection results.
- Opportunistic inspections during maintenance activities.
- Other considerations such as access and cost may be considered when the relative risk rankings are similar.

2.9 Update of Risk Ranking

Recommendation Risk-12, Ranking Update: The risk ranking should be periodically reviewed and updated as necessary.

It is recommended that the risk ranking be periodically updated to include:

- Results of inspections and fitness-for-service assessments.
- Changes to cathodic protection.
- Results of indirect inspections.
- Repairs and replacements.
- System modifications.
- Changes to system operating conditions.
- Results of leak detection.
- Changes to water treatment.
- Condition reports.

The definition of segments should also be reviewed and updated as necessary based on the above information.

3
INSPECTION

This chapter describes methods for the inspection of buried pipe (Figure 3-1). These include coating inspections, nondestructive examinations (NDE) and hydrostatic testing. Since the NDE techniques are commonly applied in nuclear plants, some with ASME Section XI rules, plants will typically have qualified manpower and procedures for their implementation. Appendix G and references 51 through 66 and 110 through 116 provide further information on various NDE methods.

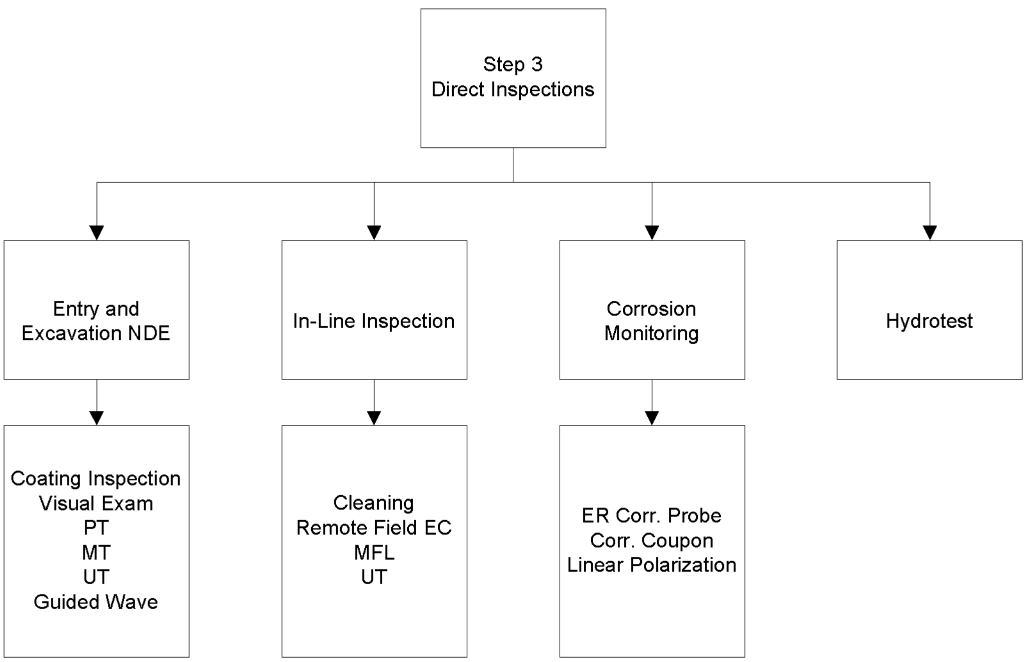

Figure 3-1
Inspection Techniques

Recommendation Direct Inspection-1, Direct Inspections: In general, inspections should be performed at the piping locations that have the highest risk rank as determined in Chapter 2. Other considerations such as access and cost may also be considered when the relative risk rankings are similar.

It is the responsibility of the owner to select the appropriate inspection method based on the site conditions and the degradation mechanisms expected for the pipe. Descriptions and cautions are provided in Appendix G.

Prior to conducting direct inspections to measure wall thickness, the Code required minimum wall thickness, t_{min}, should be determined, as described in Chapter 4, recommendation FFS-2.

3.1 Entry or Excavation NDE

Classic non-destructive examinations (surface and volumetric) are performed either by entering the pipe (if sufficiently large), use of robots or pigs, or by excavation to the pipe surface, following plant procedures. Cautions regarding entry and excavation of buried pipe are presented in Appendix F.

3.2 Coating Inspection

Recommendation Inspection-2, Coating Inspections: When a buried pipe is uncovered, the coating should be inspected by a coating inspector. The results should be documented and include relevant photographs or video.

3.2.1 Description

The coating of excavated buried pipe should be inspected for evidence of damage. A photographic record of each indication should be retained with the inspection report. Non-destructive tests are recommended. If a destructive coating test is performed the area should be repaired.

First, a visual inspection should be conducted by a qualified person for evidence of damage (mechanical damage, peeling, holiday (hole), gouge, embedded rock, blistering, flaking, rusting, etc.) and embrittlement, Figure 3-2.

Second, the condition of the coating may be characterized by testing, Figure 3-3 (reference 121). The need for the following tests should be considered:

- Blistering of coating (reference 40 or equivalent)
- Flaking (scaling) of coating (reference 41 or equivalent)
- Rusting of coated surfaces (references 42, 43 or equivalent)
- Measurement of coating thickness (references 44 through 48 or equivalent)

3.2.2 Application

- Coating inspection provides an indication of the type and extent of external corrosion.
- On cathodically protected pipes, coating damage may cause inadequate CP and signal the need to re-evaluate the adequacy of the CP system and settings.

3.2.3 Limitations

- Coating inspections should be performed by a coating inspector, such as a NACE level 1 Coating Inspector or equivalent (references 48 through 50).
- Coating inspections are difficult to conduct unless the coating surface is cleaned.

3.3 Lining Inspection

- The recommendations and guidance of Section 3.2 also apply to inspection of linings.

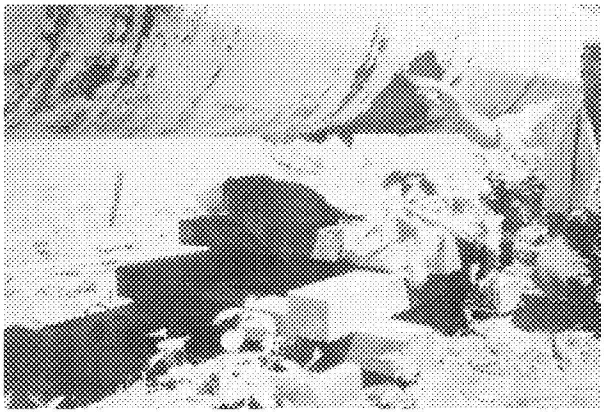

Figure 3-2
Embrittlement of Coating

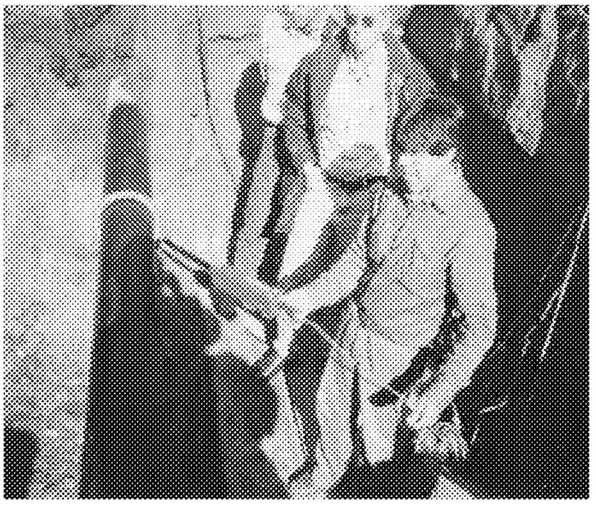

Figure 3-3
Field Inspection of Coating

3.4 Surface Examination Techniques

Recommendation Inspection-3, Pipe Inspections: When a buried pipe is uncovered (OD) or entered (ID) for any reason, as a minimum it should be visually inspected for evidence of corrosion or damage. The results of the inspection should be documented and any relevant photographs or videos should be included.

Once the pipe wall is made accessible, it can be inspected by using one of the examination techniques described in Appendix G:

- Visual examination.
- Liquid penetrant testing.
- Magnetic particle testing.
- Ultrasonic testing.
- Guided wave.
- Radiography.
- Pulsed eddy current testing.
- New methods in development.

Particular attention should be paid to the joints, especially welds, as they often are more susceptible to degradation than the base metal.

Recommendation Inspection-4, Volumetric Inspections: Where deemed necessary, a volumetric examination technique should be used to determine wall loss, measure remaining thickness, or to examine a weld. Results should be evaluated for fitness-for-service.

3.5 Hydrotest

Pressure decay is recognized as a test method in ASME Section XI (reference 70). Either the rate of pressure decay in an isolated line or the change of flow in an operating line may be monitored.

An alternative to pressure decay is to purposely burst the corroded pipe sections while the system is out-of-service. Further information on pressure decay and destructive burst testing, and their shortcomings and cautions, is provided in Appendix G.9.

3.6 Scope Expansion

If the results of the direct inspections are not consistent with predictions or results of the risk analysis, then the inspection scope should be expanded to determine the extent of the discrepancies. Locations to be considered for such scope expansions include:

- Lines having similar material, coating and burial conditions (if damage was OD initiated).
- Lines having similar material, lining, fluid, and operating conditions (if damage was ID initiated).

3.7 Corrosion Monitoring

The local corrosion rate of buried pipe can be measured for specific locations using corrosion coupons or corrosion probes. This information is quite valuable as it provides a direct and quantitative measurement of the extent of wall loss. Corrosion monitoring techniques are described in Appendix H.

4 FITNESS-FOR-SERVICE

The evaluation of the fitness-for-service (FFS) of a degraded buried pipe can be represented as a five-step process 4.1 to 4.5 as depicted in Figure 4-1.

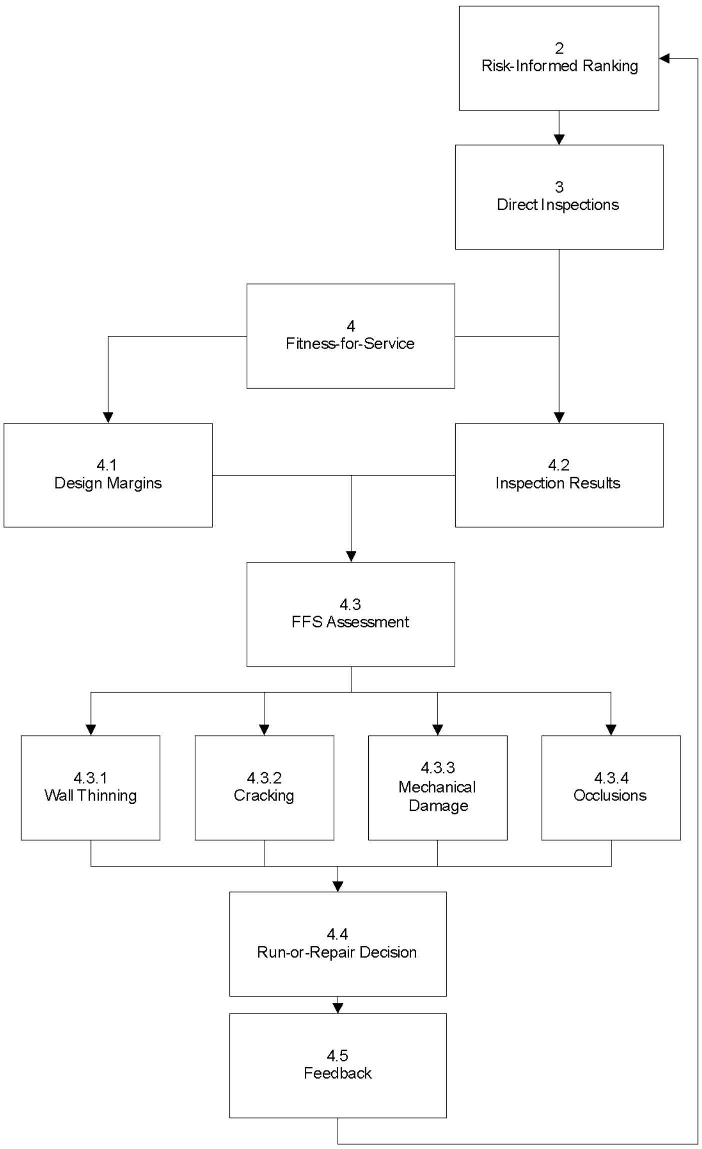

Figure 4-1
FFS Process

- The first step of the fitness-for-service (FFS) assessment of a buried piping system is to establish the design basis and design margin of the system. The design basis consists of design input and design calculations, including the design margins against the original construction code. If this data is not available or is incomplete, it will have to be developed.
- The second step of the FFS assessment is to assemble the direct inspection results, obtained from Chapter 3 Inspection. It is needed to determine the degradation mechanism (wall thinning, cracking, mechanical damage, occlusions) and estimate the future corrosion allowance (FCA), which is the projected future degradation until the next inspection or until repair.
- The third step of the FFS assessment is to select and apply the appropriate FFS assessment method, given the degradation mechanism. The FFS assessment calculates the adequacy for continued service and the margin to failure of the buried pipe, given the FCA and future damage.
- The fourth step is the run-or-repair decision, including the selection of the repair technique (Chapter 5) and preventive measures (Chapter 6).
- The fifth step is the feedback to the risk ranking process and the resulting inspection plan. Augmented inspections may be required based on plant procedures (reference 117).

4.1 Design Margins

Recommendation FFS-1, Design Analysis: The integrity assessment should be based on the design analysis of the buried piping system. The analysis should be retrieved or re-created if it cannot be retrieved.

The FFS assessment requires a baseline design analysis of the buried piping system, in accordance with the original design and construction code, typically ASME B31.1 (reference 13), B31.7, ASME Section III (reference 12), or AWWA (references 10, 11) .

The analysis should address the operating and design loads and determine that the loads, stresses and movements are within the design Code and design specification limits. The loads to be considered in the design of buried pipes should include, as applicable:

- Fluid pressure (internal, and over-pressure transients).
- Soil weight.
- Surface loads.
- Ground settlement.
- Constrained thermal expansion and contraction.
- Seismic (wave passage and anchor movement).
- Frost heave.
- Building settlement.

The criteria for analysis should be those of the design Code. Additional guidance for design equations for buried pipe may be obtained from the American Lifelines Alliance (reference 73).

Recommendation FFS-2, Minimum Code Requirement: The Code required minimum design thickness, t_{min}, to be used in the FFS assessment should be determined before the direct inspections.

The design analysis calculations will provide the minimum wall thickness, t_{min}, required by the design Code to sustain all the design stresses within Code allowables. It can be used to provide a quick indication of the severity of wall thinning. It is a necessary input to the FFS assessment.

4.2 Inspection Results

Recommendation FFS-3, Inspection Data*:* The inspection results should be compiled and categorized. A projection of future damage should be estimated based on current inspection results and the time to the next planned inspection or repair.

Inspection results are used as input to the FFS assessment. Based on the inspection results, degradation may be classified in one of four categories:

- Wall thinning: including general corrosion and localized corrosion such as pitting and crevice corrosion.
- Cracking: including environmentally assisted cracking such as stress corrosion cracking and corrosion fatigue.
- Mechanical damage: including buckle, dent, gouge, etc.
- Occlusion: including reduction in flow area, loose debris, etc.

In each case, the review should estimate the projected future damage. This estimate should be performed on a case-by-case basis, taking into consideration the total damage-to-date, and an engineering evaluation of its cause. The projected future damage should be quantified as follows:

- Wall thinning: future corrosion allowance (FCA) is the projected further loss of wall between the latest inspection and the next planned inspection or repair.
- Cracking: future crack growth (length, orientation and depth).
- Mechanical: future increase in severity of buckle, dent, gouge, etc.
- Occlusion: future growth of ID surface deposits and flow constriction.

The fitness-for-service assessment should be performed for each inspection location.

4.3 FFS Assessment

General guidance for performing fitness-for-service assessments for degraded buried pipes is provided in Appendix I.

Recommendation FFS-4, FFS Assessment Method: Methods and criteria should be in place, prior to inspections, to assess the significance of inspection results, by applying the appropriate FFS assessment method, consistent with the damage mechanism and licensing commitments.

The codes and standards for assessment of the remaining life of degraded piping systems are listed in Appendix I.

When performing a fitness-for-service assessment, it is necessary to evaluate the current degraded condition as measured by NDE (Chapter 3) extrapolated to the condition at the next inspection. For wall thinning this means that a future corrosion allowance (FCA) needs to be subtracted from the current wall thickness reading to project the wall loss till the next inspection or time of repair or replacement.

4.4 Run-or-Repair

The results of the FFS assessment will indicate whether the defect (wall thinning, cracking, mechanical damage, occlusions) is acceptable until the next inspection, or whether a repair or replacement is necessary, and when the repair should be implemented. Repair techniques are described in Chapter 5, and preventive rehabilitation techniques to reduce risk are described in Chapter 6.

4.5 Feedback

Recommendation FFS-5, Feedback: The knowledge gained through the FFS process should be used to review and adjust as necessary the risk ranking and the inspection plan.

- A significant amount of data is gathered and analyzed through the FFS process. Failure modes should be analyzed in detail, predictions of future damage should be performed, and margins should be established. This data should be used to revisit the risk ranking process of Chapter 2, and make the necessary adjustments to the likelihood of failure modes, consequence of failure, risk ranking, inspection locations, methods and intervals.

Existing plant procedures and commitments regarding augmented inspections should be followed (reference 117).

5
REPAIRS

5.1 Overview

Pipe repairs can be grouped into two broad categories: welded repairs and non-welded repairs. Each category includes various repair options, listed in Figure 5-1 and presented in this Chapter with further information in Appendix K. Other good compendiums of repair techniques include:

- For safety-related buried piping systems:
  - ASME Section XI In-Service Inspection (reference 70) and Code Cases as approved by the NRC for the station.
  - EPRI report TR-10217, Service Water System Repair/Replacement Guidelines (reference 90).
  - NRC Generic Letter 90-05 (reference 117).
- For non-safety-related buried piping systems:
  - ASME Post-Construction Code PCC-2 (reference 88).
  - PRCI Pipeline Repair Manual (reference 89).

In all cases, the selected repair technique should be reviewed against the regulatory requirements and licensing commitments of the plant to determine if it is prohibited or is permitted only under certain circumstances.

Following repair, the risk ranking should be reviewed and revised as necessary, as illustrated in Figure 1-1.

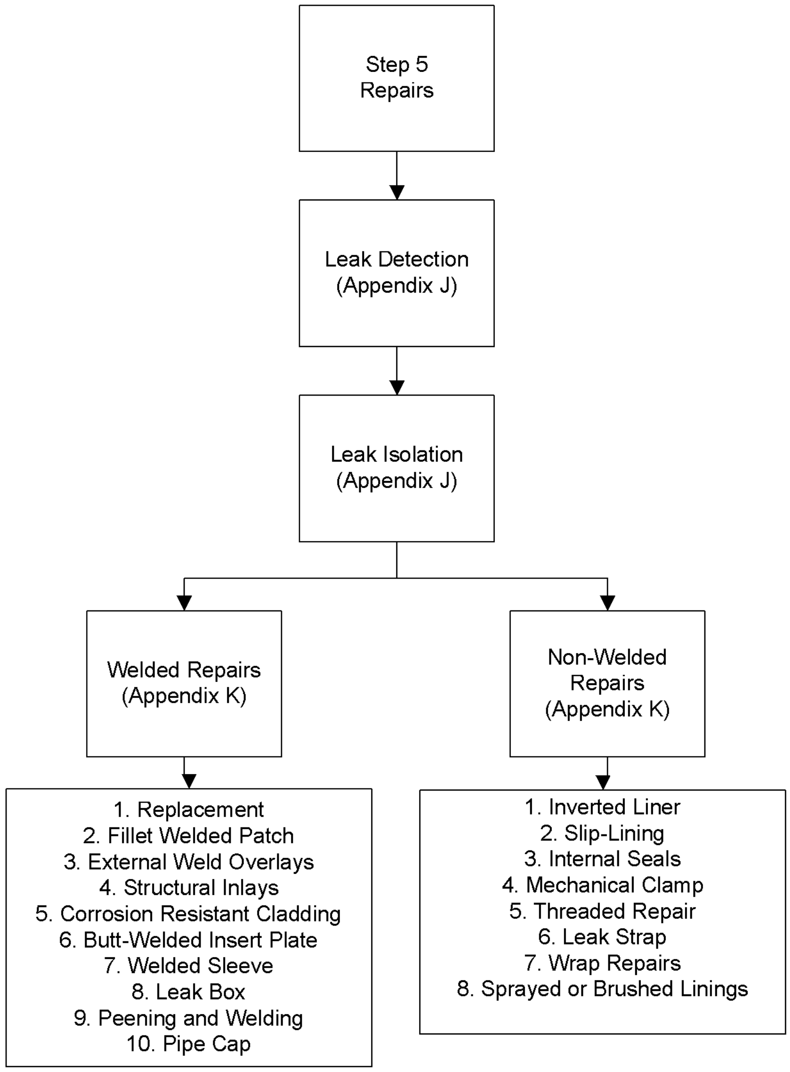

Figure 5-1
Overview of Repair Techniques

5.2 Repair Plan

A repair plan should be developed that addresses the following points:

1. The effect of the repair on flow conditions and system operations.
2. The selection of the repair materials, their compatibility with the operating environment and postulated service conditions (including accident conditions), and their corrosion life It is at this stage that a design life should be assigned to a repair, rather than labeling a repair as "temporary" or "permanent." Re-inspection or replacement of a repair should be determined and documented based on the projected design life.
3. The mechanical design and strength of the repair for normal operating loads and postulated accidents, including seismic for safety-related lines. This is typically done through stress analysis in accordance with a design Code and the corresponding standards.

4. The definition of shop fabrication and field installation requirements, including process and personnel qualifications, nondestructive examination, and pressure or leak testing of the repair.
5. The control of operating conditions to assure that they are within the material and design limitations.

Recommendation Repair-1, Pre-Approved Repair Options: Pre-approved repair options should be in place for prompt implementation in case a buried pipe fails. The detailed design of the selected repair option should accommodate the specifics of the failed line.

5.3 Leak Detection and Isolation

Recommendation Repair-2, Leak Detection and Isolation: Leak detection techniques and leak isolation options should be pre-selected for prompt implementation should a leak occur.

Examples of techniques for leak detection and isolation are described in Appendix J.

6
PREVENTION, MITIGATION AND LONG-TERM STRATEGY

In addition to the immediate repair, if the risk of failure is unacceptably high, it is recommended that measures be taken to prevent failures from recurring and to mitigate their consequence (Figure 6-1). In the oil and gas pipeline industry these activities are referred to as pipeline rehabilitation measures.

Recommendation Prevention-1, Retrofit: Where the risk of failure is unacceptable, preventive and mitigative options should be implemented.

Measures to prevent fluid-side (ID) degradation include water treatment, cleaning and lining.

Measures to prevent soil-side (OD) degradation include coating, cathodic protection, and special trench fill.

Measures to prevent fluid-side and soil-side degradation include pipe replacement by a different material.

Measures to mitigate failure include prompt leak detection, leak source location and repair.

Prevention and mitigation techniques and leak detection are described in Appendix L. Repairs are addressed in Chapter 5 and Appendix K.

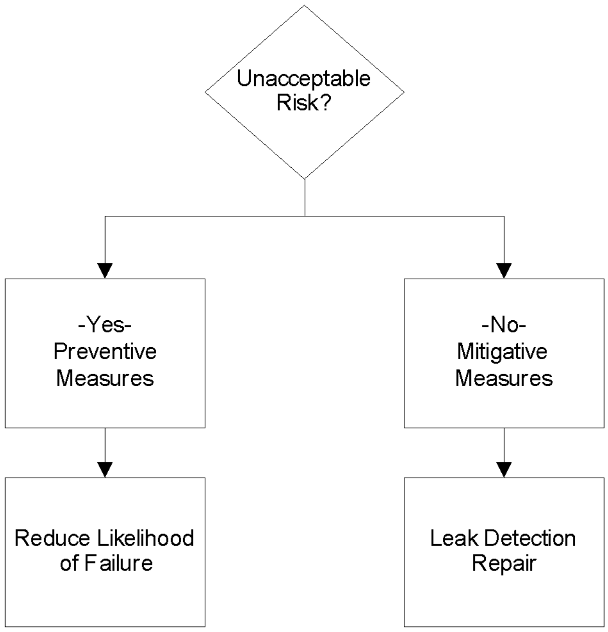

Figure 6-1
Prevention and Mitigation

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A
RECOMMENDATIONS

A.1 Procedures and Oversight

A.1.1 Policies and Procedures

A Buried Pipe Integrity Program Plan and implementing procedures should be developed.

A.1.2 Program Database

A database should be developed to track key program data and performance indicators.

A.1.3 Performance Indicators

System or program health reports and performance indicators should be developed for the Buried Pipe Integrity Program. The performance indicators should be periodically tracked and reported to management.

A.2 Risk Ranking

A.2.1 Scope Drawings

A set of as-built drawings should be assembled, showing the buried pipe routes, including their location relative to other buried and aboveground buildings, structures and commodities.

A.2.2 Route Confirmation

The buried pipe routes and adjacent buried commodities should be confirmed through field surveys.

A.2.3 Scope Exclusions

Buried piping segments whose failure is inconsequential, and would cause no direct or collateral damage (as described under Section 2.6 Consequence Assessment), may be excluded from the scope of the buried piping integrity program.

A.2.4 Data Collection

Line-specific data should be collected and compiled for use in risk ranking, inspection planning and fitness-for-service assessment. The line should be subdivided into segments of similar characteristics.

A.2.5 Soil Analysis

Soil analysis data should be collected to assess the likelihood of OD corrosion.

A.2.6 CP Check

Where buried pipes are protected by a cathodic protection (CP) system, the CP system should be periodically inspected and tested to assess its continued adequacy.

A.2.7 Over-the-Line Surveys

It is recommended that over-the-line surveys be conducted as part of Step-2, Risk Ranking, to help assess the likelihood of OD corrosion. The surveys should be conducted periodically and the likelihood of corrosion should be updated accordingly.

A.2.8 ID Corrosion Assessment

The potential for fluid-side corrosion and fouling of buried pipe should be evaluated to determine the likelihood of failure.

A.2.9 Likelihood of Failure

The likelihood of failure (e.g., low, medium, high) should be determined for each segment of the buried pipe system for each failure mode.

A.2.10 Consequence of Failure

A consequence of failure should be determined for each segment and each failure mode.

A.2.11 Risk Ranking

Following the determination of likelihood and consequence of failure for each segment and each failure mode, a risk rank should be determined for each segment in order to prioritize inspections or other failure prevention measures.

A.2.12 Ranking Update

The risk ranking should be periodically reviewed and updated as necessary.

A.3 Inspections

A.3.1 Inspections

In general, inspections should be performed at the piping locations that have the highest risk rank as determined in Chapter 2. Other considerations such as access may also be considered when the relative risk rankings are similar.

A.3.2 Coating Inspections

When a buried pipe is uncovered, the coating should be inspected by a coating specialist. The results should be documented and include relevant photographs or video.

A.3.3 Pipe Inspections

When a buried pipe is uncovered (OD) or entered (ID) for any reason, as a minimum it should be visually inspected for evidence of corrosion or damage. The results of the inspection should be documented and any relevant photographs or videos should be included.

A.3.4 Volumetric Inspections

Where deemed necessary, a volumetric examination technique should be used to determine wall loss, measure remaining thickness, or to examine a weld. Results should be evaluated for fitness-for-service.

A.4 Fitness-for-Service

A.4.1 Design Analysis

The integrity assessment should be based on the design analysis of the buried piping system. The analysis should be retrieved or re-created if it cannot be retrieved.

A.4.2 Minimum Code Requirement

The Code required minimum design thickness, t_{min}, to be used in the FFS assessment should be documented before the direct inspections.

A.4.3 Inspection Data

The inspection results should be compiled and categorized. A projection of future damage should be estimated based on current inspection results and the time to the next planned inspection or repair.

A.4.4 FFS Assessment Method

Methods and criteria should be in place, prior to inspections, to assess the significance of inspection results, by applying the appropriate FFS assessment method, consistent with the damage mechanism and licensing commitments.

A.4.5 Feedback

The knowledge gained through the FFS process should be used to review and adjust as necessary the risk-informed ranking and the inspection plan.

A.5 Repairs

A.5.1: Pre-Approved Repair Options

Pre-approved repair options should be in place for prompt implementation in case a buried pipe fails. The detailed design of the selected repair option should accommodate the specifics of the failed line.

A.5.2: Leak Detection and Isolation

Leak detection techniques and leak isolation options should be pre-selected for prompt implementation should a leak occur.

A.6 Prevention, Mitigation and Long-Term Strategy

A.6.1 Retrofit

Where the risk of failure is unacceptable, preventive and mitigative options should be implemented.

B

BIBLIOGRAPHY FOR BURIED STEEL PIPE INTEGRITY

For information, this appendix lists selected publications related to the integrity of buried steel pipe. The methods and guidelines presented in these publications have been considered in developing these recommendations.

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5. RP0102 In-Line Inspection of Pipelines

6. SP0502 Pipeline External Corrosion Direct Assessment Methodology

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B.3 American Petroleum Institute (API)

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8. Corrosion, ed. L.L. Shreir, R.A. Jarman, G.T. Burstein, Butterworth and Heinmann
9. Control of Pipeline Corrosion, A.W. Peabody, NACE International
10. Specialized Surveys for Buried Pipelines, Publication 54277, NACE International
11. Buried Pipe Design, A. Moser, McGraw-Hill
12. Piping and Pipeline Engineering, G. Antaki, Chapter 14 Buried Pipe, M. Dekker
13. Pipeline Design and Construction, M. Mohitpour, H. Golshan, A. Murray
14. Structural Mechanics of Buried Pipes, R.K. Watkins, L.R. Anderson, CRC Press
15. Fitness-for-Service and Integrity of Piping, Vessels, and Tanks, G. Antaki, McGraw-Hill
16. Defects and Failures in Pressure Vessels and Piping, H. Thielsch, Krieger Publishing Company.
17. Underground Piping Handbook, L.A. Peggs, Krieger Publishing Company.

C
EXAMPLES OF BURIED PIPING SYSTEMS

Following is a list of piping systems that may have one or more buried segments. This is not a complete list, each station should perform a thorough review to identify systems with buried segments.

Active Drainage

Auxiliary Feedwater

Auxiliary Gas

Building Drains

Chemical Injection

Chlorination

Circulating Water

CO2

Condensate and Feedwater

Cooling Oil

Demineralized Water

Diesel Generator Fuel Oil

Domestic Water

Emergency Coolant Injection

Emergency Storage Water

Essential Service Water

Fire Protection

Frazil Ice Protection

Fuel Oil

High Pressure Coolant Injection (HPCI)

Hydrogen

Instrument Air

Liquid Effluent Sampling and Monitoring

Lubrication Oil

Lubrication Oil Waste Disposal

Make-up Water

Non-essential Service Water

Off-gas

Pipe Trench Inactive Drainage

Radwaste

Reactor Core Isolation Cooling (RCIC)

Refueling Water

Roof Drainage

Service Air

Sewage System

Steam Generator Blowdown

Tempering Water

Trash Removal

Yard Fire Protection

D
SOIL SAMPLING AND ANALYSIS

Soil near the buried pipe (i.e., from the pipe trench at burial depth) should be sampled and subject to chemical and biological analyses to provide an indication of its corrosivity. A probe is used to drill vertically down and collect a column of soil from the ground surface down to pipe depth (Figures D-1 and D-2), applying caution to prevent gouging or puncturing the pipe. Soil samples can also be collected under concrete floors by drilling through the concrete (Figure D-3). As it is extracted, the soil column is retained in a plastic sleeve (Figure D-4), and sent to a laboratory for analysis (references 17 through 22).

Figure D-1
Truck-Mounted Geo-Probe for Soil Drilling and Sample Collection. *Source: ARM, Columbia SC, with permission*

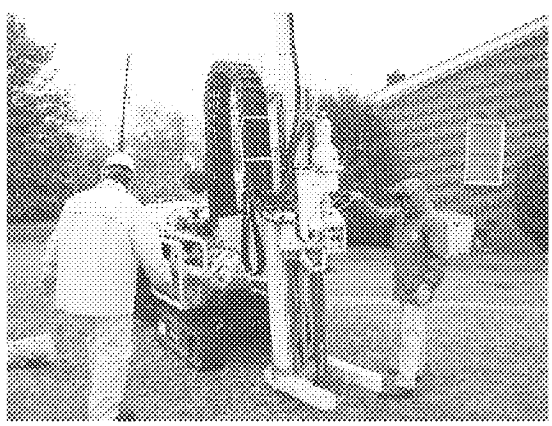

Figure D-2
Field Collection of Soil Sample. *Source: ARM, Columbia SC, with permission*

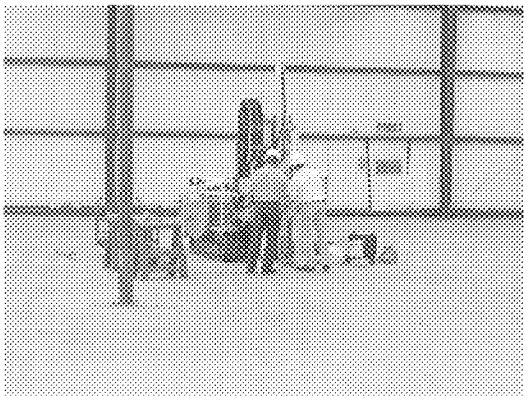

Figure D-3
Collection of Soil Sample through Concrete Mat. ***Source: ARM, Columbia SC, with permission***

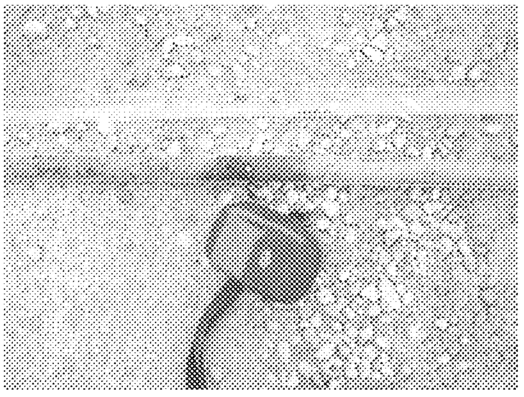

Figure D-4
Soil Sample Cylinder. ***Source: ARM, Columbia SC, with permission***

E
OVER-THE-LINE SURVEYS

E.1 Introduction

This Appendix describes methods for over-the-line surveys of buried pipe.

E.2 Pipe-to-Soil Potential

E.2.1 Description

A pipe-to-soil potential survey measures the potential difference between the pipe and the soil (the electrolyte) (references 27 and 28). One lead of a high-input impedance voltmeter is placed against the pipe, the other lead to a reference electrode touching the ground, Figure E-1.

Figure E-1
Pipe-to-Soil Potential Survey ***Source: Corrpro, Medina, OH, with permission***

E.2.2 Application

Pipe-to-soil potentials are used to evaluate corrosion activity. If properly interpreted and correlated with other measurements, pipe-to-soil potentials give an indication of the severity of galvanic and electrolytic corrosion cells (reference 28). In the absence of extraneous electrical interferences, the most actively corroding sections of pipe have the most negative potential.

On cathodically protected lines, the pipe-to-soil potential provides a measure of the adequacy of the CP settings.

E.2.3 Limitations

- The voltmeter lead must contact the pipe.
- An interrupter must be available to disconnect the pipe from the rectifier for a short period of time.
- The method provides a relative ranking of corrosivity along the line rather than a measure of corrosion rate.

E.3 Direct Current Voltage Gradient (DCVG)

E.3.1 Description

When a DC current is applied to the pipe, the current will leak out of the pipeline and into the ground at coating holidays, creating a voltage gradient in the ground at these locations. A surveyor walking the ground surface with electrode sticks over the pipeline will detect the voltage gradient as a deflection of the voltmeter needle, Figures E-2 and E-3. A series of readings laterally to the pipe help determine the magnitude of the coating defect.

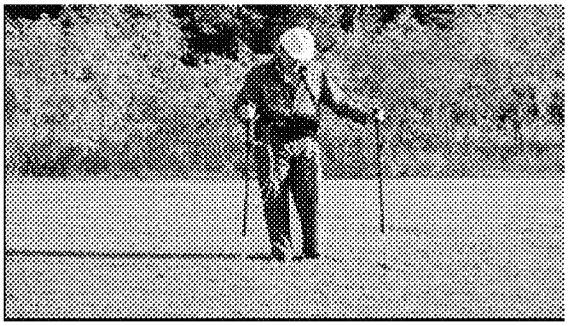

Figure E-2
DCVG Survey. *Source: Corrpro, Medina, OH, with permission*

Figure E-3
DCVG Survey. *Source: Corrpro, Medina, OH, with permission*

E.3.2 Application

The Direct Current Voltage Gradient survey (DCVG) is used to detect holidays in the coating of buried steel pipes to which an impressed DC current has been applied.

E.3.3 Limitations

- The survey must be conducted by a certified technician.
- The pipe must be located from the ground surface.
- The survey provides no CP information.
- The survey can be slow for poorly coated pipe.

E.4 Pearson Survey

E.4.1 Description

The Pearson survey measures the voltage gradient between the pipe and the soil when an alternating current is applied to the pipe, with the other terminal connected to a remote earth.

E.4.2 Application

The Pearson survey is used to detect holidays in the coating of buried steel pipes.

E.4.3 Limitations

- Same as DCVG.
- It is not as common as DCVG.
- It requires a minimum of two technicians.

E.5 AC Current Attenuation (ACCA) Survey

E.5.1 Description

An AC current applied to the pipeline creates an electromagnetic field around the pipeline which is measured by a magnetometer. The current gradually decays with distance unless there is a coating defect, in which case there is a sudden drop in current, Figure E-4.

E.5.2 Application

- The method can locate a buried steel pipeline and determine its depth.
- It can assess general coating condition over long distances.
- It does not require contact with the ground.
- It is applicable for pipelines under magnetically transparent cover, such as earth, ice, water, asphalt, or concrete.
- It can detect underground shorts of the CP system.

E.5.3 Limitations

- It is hindered by interference from AC power lines.
- It may not detect small pinholes in the coating.
- It is not a cathodic protection assessment tool.
- It is less sensitive than DCVG.

E.6 Close Interval Potential Survey

E.6.1 Description

The Close Interval Potential Survey (CIPS or CIS) (reference 29), measures the pipe-to-soil potentials at selected intervals, typically 3 to 6 ft (1 to 2 m), with the direct current cathodic protection system synchronized 'on' and 'off'. The voltmeter is connected at one end to a reference electrode (similar to a ski pole) which is placed above the pipe by the surveyor walking the ground surface over the line. The other pole of the voltmeter is connected to the pipeline, typically at a CP test station, through a trailing wire which unwinds as the surveyor walks the line, Figure E-5. The survey produces two graphs of soil to pipe voltage along the line, one for the 'on' mode and one for the 'off' mode, Figure E-6.

E.6.2 Application

- It is a quantitative survey which measures the effectiveness of cathodic protection system.
- CIPS can be used to locate coating defects.
- It detects stray current interferences and foreign contacts

E.6.3 Limitations

- It is a versatile CP survey, with few limitations.
- It only applies to cathodically protected lines.

- It works best when combined with a DCVG survey, Figure E-6.
- The presence of adjacent buried or submerged metallic structures may make data from a CIS difficult to interpret.

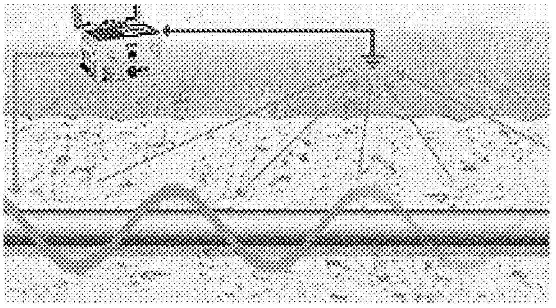

Figure E-4
Detection of Attenuating Signal

Figure E-5
CIPS. *Source: Corrpro, Medina, OH, with permission*

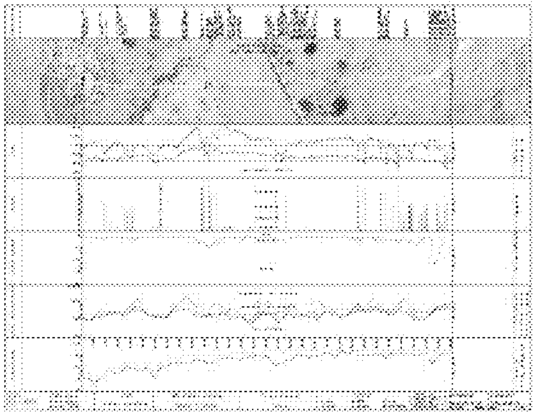

Figure E-6
Combined Survey Techniques, *Source: Corrpro, Medina, OH, with permission*

E.7 New Technologies

There is continuously new research to develop better over-the-line corrosion assessment tools. One such example is the No-Pig® technology (reference 30). An inspection current is induced between two contact points on the pipeline which generates a concentric magnetic field around the pipe. A defect disturbs the concentric field. The No-Pig® pipeline inspection system analyzes the magnetic field of a pipeline from aboveground. The technique is reported to apply to pipes 3 in to 12 in (75 to 300 mm) diameter, with wall thickness up to 0.4 in (10 mm), buried 5 ft (1.5 m) deep.

E.8 Summary of Over-the-Line Surveys

Table E-1 is a summary of the key parameters collected through over-the-line surveys and which can be used to assess the condition of the CP system, the pipeline coating and the likelihood of OD corrosion.

Table E-1
Over-the-Line Survey Methods

	Technique	Diagnostic
1	Walkdown	General and unusual conditions, photographic record
2	CP installation condition	CP adequacy
3	CP voltage, mV	CP adequacy
4	CP useage	CP adequacy
5	CP voltage trend, mV	CP adequacy
6	Stray currents, mA	CP adequacy, corrosion potential
7	DCVG, %IR	Coating, interferences
8	ACCA, mA	Route, coating
9	Pearson, mV	Coating, interferences
10	CIPS, mV	CP adequacy, coating, interferences

F
CAUTIONS FOR ENTRY AND EXCAVATION

Entry into buried pipe and excavation around buried pipe should be conducted in accordance with station procedures, with due consideration to radiological and Environmental, Safety and Health (ES&H) requirements and limitations. Certain cautions are listed here, but this list is not all-inclusive. Each station should have station-specific procedures for entry and excavation.

Cautions and procedures for entry should address:

- Confined space entry procedures.
- Survey of atmosphere prior and during entry.
- Breathing air.
- Communications.
- Isolations from water source.
- Emergency exit strategies.

Cautions and procedures for excavation should address:

- Radiological controls.
- Industrial hygiene, OSHA 29CFR1926 subpart P (shoring, side slopes, supports, etc.) (reference 39).
- Barricades.
- Confined space entry.
- Environmental protection.
- Leak disposal.
- Special procedures and controls for digs through a reinforced concrete mat.
- Implications of having a seismic category buried pipe temporarily uncovered.
- As-built and photographic records.
- Clearing the subgrade free of ponded water.

Cautions and procedures for backfill should address:

- A 6 in (150 mm) deep bedding of clean sand or equivalent is typically placed under the pipe.
- Pipe bells, flanges, etc., should be uniformly supported by the bedding.

- Clean fill should be placed in successive uniform loose layers of 9 in (225 mm) or less.
- The backfill should not contain rocks or gravel 3 in (75 mm) or larger, organic substance, sludge, rubbish, frozen soil, etc.
- Alternatively, and following feasibility analysis, controlled low strength material (CLSM, a composite of sand, fly-ash, cement and water) may be poured around the pipe.
- Vibratory or rolling compaction should be used to obtain the required dry density.
- Surface marking should be used to indicate the location and routing of the pipe.

G
DIRECT INSPECTIONS

Direct inspection techniques are inspections based on direct access to the pipe wall and use non-destructive examination (NDE) techniques (reference 116). Additional information can be found in references 51 through 63.

G.1 Visual Examination

G.1.1 Description

Internal inspections may be conducted by entering pipes, where safe and feasible, or by remote visual inspection such as a borescope, Figure G-1. In the case of borescope inspection, it is recommended to also record the surface condition of a new pipe of the same material for comparison.

G.1.2 Application

The visual inspection should address:

- Signs of visible corrosion (pitting, wall thinning, rust, surface deposits, cracks, etc.).
- Signs of visible damage (dents, gouges, grooves, cracks, etc.).
- Pit depth, using a pit gage, Figure G-2.

A photographic record of significant indications should be retained with the inspection report.

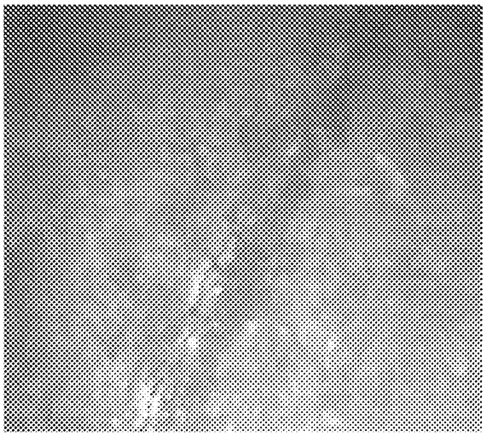

Figure G-1
ID Crack Detected by Borescope Inspection

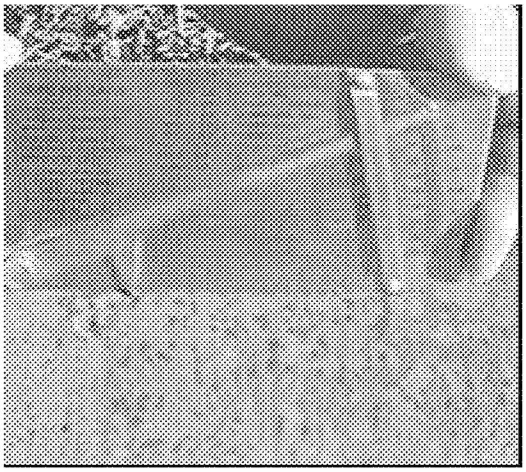

Figure G-2
Pit Depth Measurement

G.1.3 Limitations

- Access to the pipe surface may be hindered by deposits, congestion or coating.
- Access to the bottom OD of the pipe may not be feasible without mirrors.
- Experience is required in differentiating between surface rust and deep corrosion

G.2 Liquid Penetrant Testing

G.2.1 Description

Liquid penetrant testing (PT) is an extension of visual examination typically used to examine a component for the presence of surface-breaking discontinuities such as cracking, pitting, holes, and porosity. There are a variety of techniques that are routinely used ranging from a relatively quick solvent-removable visible penetrant to a more time consuming and sensitive post-emulsifiable fluorescent penetrant technique. Selection of the technique is dependent on desired sensitivity and time constraints. For examination of piping for the presence of relatively large indications, a color contrast solvent-removable technique is typically adequate.

There are essentially six steps to the color contrast solvent-removable process:

1. The examination surface must first be adequately prepared by removing contaminants such as dirt and rust.

2. A solvent pre-cleaner is applied to the surface to dissolve oils and remove soils to prepare the surface.

3. Once the surface is dry, a liquid penetrant material capable of seeping into a surface discontinuity is applied to the examination surface. The penetrant is left in contact with the surface for prescribed dwell times to allow the penetrant to seep into surface discontinuities.

4. Excess penetrant is carefully removed from the surface so penetrant is not removed from a discontinuity.

5. A developer is applied to the surface which acts as a blotter to draw the penetrant out of the discontinuity.

6. The examination surface is observed over a prescribed period of time to identify the presence of discontinuities.

Figure G-3 is a picture of a crack using a color contrast visible liquid penetrant examination.

Penetrant systems are designed so there is a significant contrast between the penetrant and the developer. A typical color contrast technique will consist of a red penetrant and a white developer. Penetrant material has low viscosity and high surface tension properties.

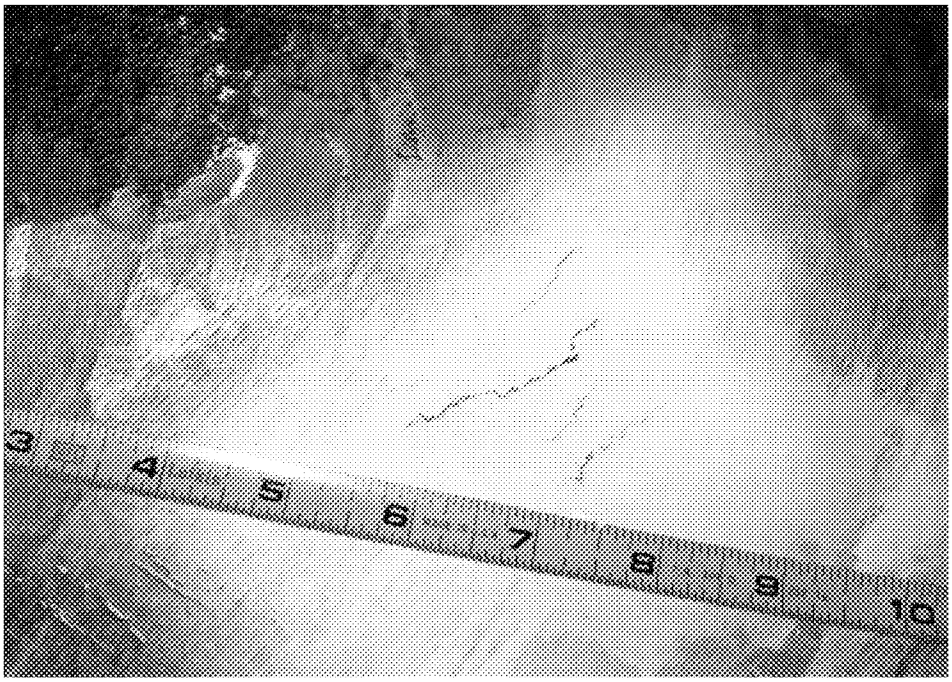

Figure G-3
Visible Dye Penetrant Indication of Cracking

G.2.2 Application

While liquid penetrant can be used on ferrous and non-ferrous piping, it is typically only used on non-ferromagnetic materials such as stainless steel piping as it is normally more time consuming than magnetic particle techniques.

Examination records are obtained by drawing detailed sketches and or taking pictures. It is important to include measuring devices such as tapes or rulers in the picture. It is also recommended to include landmarks in the picture or to retain accurate notes of the location and orientation of the pictures.

G.2.3 Limitations

PT is a surface examination method and is affected by surface cleanliness, roughness or porosity. The discontinuity must be open to the surface and the examination surface must be adequately cleaned as a discontinuity filled with dirt or oxide may not be detected.

While the technique is relatively straightforward, there are pitfalls that can cause the process not to work effectively. Therefore, it is important to use trained and qualified NDE personnel in conjunction with good procedures.

G.3 Magnetic Particle Testing

G.3.1 Description

Magnetic particle examination methods are used to detect surface and near surface discontinuities in ferromagnetic materials. A magnetic field is established between poles in a magnetized object. Surface-breaking discontinuities (or near surface breaking in some cases) disrupt the magnetic field and cause flux lines to exit and re-enter the surface. When finely divided ferromagnetic particles are applied to the magnetized surface, they will be attracted to these locations and form a visible image of the discontinuity. Electrical fields can be induced in a variety of ways such as with coils, prods or yokes. Particles can be color contrast dry visible or fluid suspended fluorescent.

There are a variety of routinely used magnetic particle examination techniques. Technique selection is based on the purpose and sensitivity requirements of the examination. The most commonly used method for pipe inspection is the use of a yoke and dry color contrast ferromagnetic particles. The yoke is essentially a horseshoe shaped magnet made from soft iron that is longitudinally magnetized by a small coil producing flux that travel from the south pole (one leg) through the piece to its north pole (other leg). The ferromagnetic particles are lightly applied to the piece as the yoke is energized. The examined surface is observed during this process to identify the discontinuity. The particle pattern will typically remain after the yoke is de-energized; however, it may not be as well defined and, in some cases, will not remain intact. A picture of a yoke examination is shown in Figure G-4.

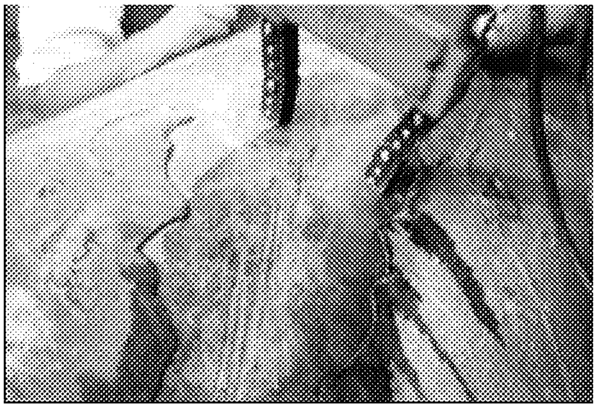

Figure G-4
MT of Exposed Pipeline

The magnetic field must be induced in a specific orientation to the discontinuity. If the discontinuity orientation is unknown, the magnetic field must be applied in two directions to obtain full coverage.

G.3.2 Application

Like liquid penetrant testing (PT), the main purpose of magnetic particle testing (MT) is to detect cracks in piping welds or in their vicinity.

Examination records are obtained by drawing detailed sketches and or taking pictures. It is recommended to include measuring devices such as tapes or rulers in the picture. It is also a good idea to include landmarks in the picture or to retain accurate notes of the location and orientation of the pictures.

G.3.3 Limitations

- MT can only be applied to ferromagnetic materials, such as carbon steel, and not to austenitic stainless steel.
- The examination surface must be relatively smooth to permit the free flow of magnetic particles.
- Demagnification may be necessary if residual magnetism is an issue.
- Detection of sub-surface discontinuities is limited and requires the use of special techniques.
- Wide discontinuities may not be detected.

G.4 Ultrasonic Examination

G.4.1 Description

Ultrasonic examination is conducted by transmitting high frequency (0.5 to 15 MHz range) ultrasonic energy into a component and monitoring its response. Ultrasonic energy is typically transmitted into a material with a transducer containing a piezoelectric crystal. A liquid couplant is placed between the transducer and the component, and a voltage is applied to the transducer with ultrasonic instrumentation causing the crystal to vibrate. The energy is transmitted through the couplant into the specimen where it travels until the energy is reflected or otherwise returned to the transducer, or the energy dissipates. Energy reflected back to the transducer deforms the crystal resulting in voltage that is then processed and displayed by the instrumentation.

The most common ultrasonic technique used for piping applications is called “pulse-echo” where a single transducer both sends and receives the ultrasonic energy. An illustration of this is provided in Figure G-5. There are many transducer and instrumentation variables that can be used to optimize the technique for the application. Qualified ultrasonic personnel using demonstrated procedures detailing equipment selection, calibration, and examination techniques should be used to obtain optimal results.

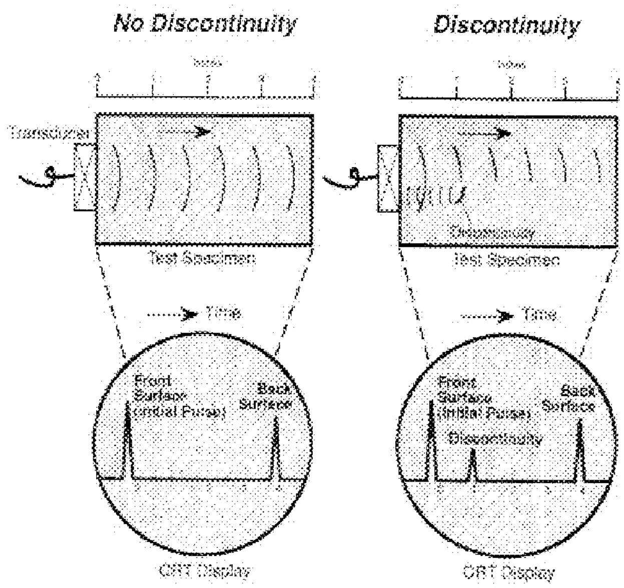

Figure G-5
Straight Beam Ultrasonic Testing

The ultrasonic data can be displayed in a variety of ways. The most commonly used display is the A-scan which displays time on the horizontal axis and signal amplitude on the vertical axis. Other displays used in piping examinations are B-scan and C-scan. The B-scan is a cross-sectional slice of data that shows time on the vertical axis and scan length on the horizontal axis. The C-scan is a "top view" that shows the two-direction scan pattern on the horizontal and vertical axis. Color is used in the C-scan to represent time, amplitude or frequency. For thickness examination, it is typically set to represent time or thickness. Computerized analysis systems can be used to display all of these views.

Time is used to determine the location of the reflector as most piping materials have a known velocity and the angle the sound is delivered in the pipe is known. Signal shape, frequency, amplitude as well as associated signals can be used to characterize the indication. The extent of the analysis is dependent on the specific application.

G.4.2 Application

Highly accurate thickness measurements can be made with ultrasonic examination techniques using 0° transducers. It is important to note that only the thickness immediately below the transducer is measured. To overcome this limited scope examination, the transducer can be scanned over the pipe to identify the thinnest area, a range of thicknesses, or to map out prescribed thickness ranges. An example of this would be to map the area of the pipe containing a thickness below minimum wall thickness. Another method commonly used is to grid the pipe and take point thickness readings at the grid intersections. Grid sizes can be strategically determined to assure the identification of thinning of a certain size.

Another common application of ultrasonic examination is the examination of welds to identify flaws that could be detrimental to the service life of the piping system. This is commonly accomplished using angle beam transducers. Ultrasonic techniques are available to detect and accurately characterize indications. These techniques are more complex than 0° degree and hence require the use of highly qualified ultrasonic personnel and procedures.

G.4.3 Limitations

- Ultrasonics, especially weld examination techniques, can be complex and require the use of skilled, qualified ultrasonic personnel and procedures.
- Surface finish must be adequate to couple the ultrasonic energy from the transducer into the component. Surface preparation or the use of specialized ultrasonic techniques may be required.
- For commonly used 0° thickness examination techniques, flat inner and outer surfaces must be essentially parallel to measure thickness.
- Special techniques may be required to detect certain flaw types such as small isolated pits.
- Near surface flaws can be difficult to detect unless specialized techniques are used.

G.5 Guided Wave

G.5.1 Description

Guided wave (GW) is an ultrasonic technology that, unlike conventional ultrasonic and eddy current techniques, can be used to examine large lengths of pipe from a single probe location. In addition, it provides the possibility of examining inaccessible portions of pipe that would otherwise have to be excavated or entered with an inspection device (reference 64).

Guided wave energy is generated in the material by positioning the probe in contact with the material and pulsing it with an electrical charge to transmit a mechanical vibration into the component. The waves are reflected and mode-converted off the inner and outer walls of a pipe and eventually result in a GW that travels down the length of the pipe.

There are several different GW modes that can be generated, including longitudinal, torsional, flexural, Lamb, shear-horizontal, and surface. The waves have different properties that may be advantageous for certain applications. Since torsional waves are not significantly dampened by liquids contained in the pipe and have a constant velocity, they are typically used for buried pipe inspection. Under ideal conditions, GWs can travel relatively significant distances within a pipe; however, there are limitations as discussed later.

The probes that generate the energy into the pipe consist of piezoelectric elements or magnetostrictive sensors (MsS). An example of a piezoelectric piping probe is shown in Figure G-6. This particular probe contains two rings of piezoelectric elements that are clamped around a pipe. The outer portion of the probe contains an air bladder, which when inflated presses the transducers in firm contact with the pipe to the extent that couplant is not required. Figure G-7 is a close-up shot of the piezoelectric elements used in the piping probe. An example of a magnetostrictive sensor probe used on a pipe is shown in Figure G-8.

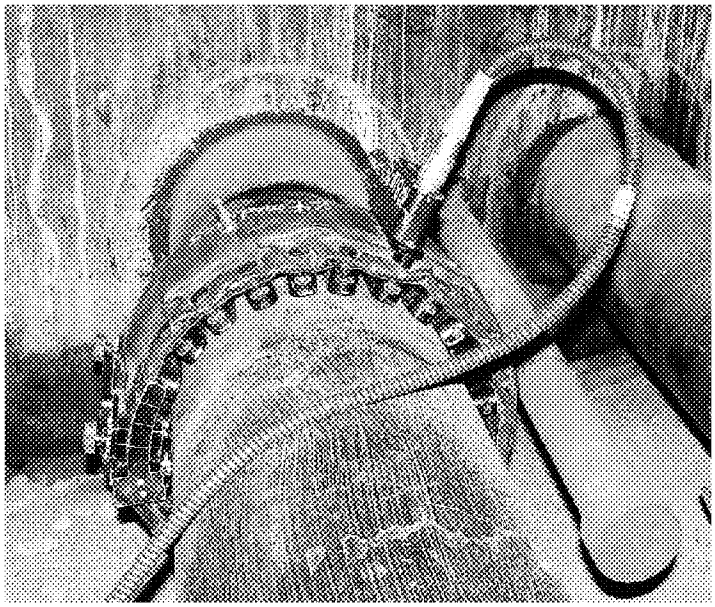

Figure G-6
Piezoelectric GW Piping Probe

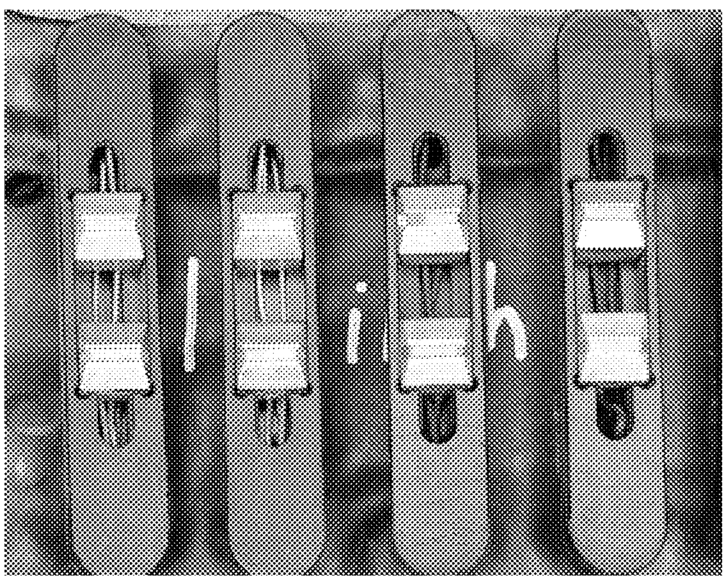

Figure G-7
Piezoelectric GW Elements

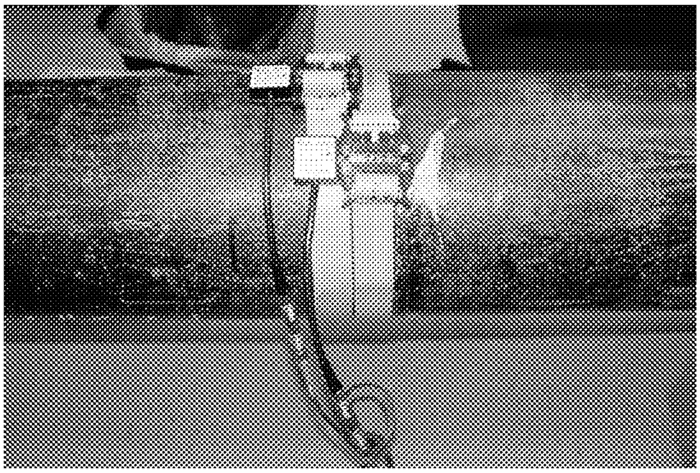

Figure G-8
Magnetostrictive Sensor GW Probe

Once the GW is generated in the material, the probe is put into a receive mode to "listen" for reflected energy. Changes in structure geometry, such as a change in wall thickness or the presence of a discontinuity, cause an impedance change that results in a portion of the GW energy being reflected. Both a loss (such as wall loss) and an addition in wall thickness (such as a weld crown) can cause a reflection. The extent of the reflection is dependent on the difference in acoustic impedance at the location—the higher the difference, the more energy reflected. A crack perpendicular to the sound propagation with a sufficient cross-sectional volume will also reflect energy. Reflected energy sensed by the probe will be converted from mechanical energy into an electrical signal that is recorded and presented on the GW system.

Guided wave's sensitivity to detect wall thickness change is not nearly as sensitive as traditional ultrasonics. GW pipe inspection measures a change in cross-sectional area for a 360° circumferential slice of the pipe whereas conventional ultrasonics very accurately measures wall thickness at the transducer location. Achievable GW sensitivity is dependent on many factors including equipment, piping configurations, conditions surrounding the pipe, analysis software, etc. Detection thresholds are also affected by pipe diameter and thickness. For a specific sensitivity level, the minimum detectable reflector increases in size as the pipe gets thicker and larger in diameter.

Data analysis can be quite difficult, the level of which is dependent on several variables such as system configuration. A typical data analysis screen display is a radio frequency A-scan presentation with signal amplitude on the vertical axis and time on the horizontal axis. Amplitude is indicative of the amount of reflected energy received by the probe. The time axis presents the time between the initial pulse and the reception of the reflected signal. The time can be used to calculate the distance that the reflector is from the probe. An example of a screen presentation obtained from piping containing degradation is provided in Figure G-9.

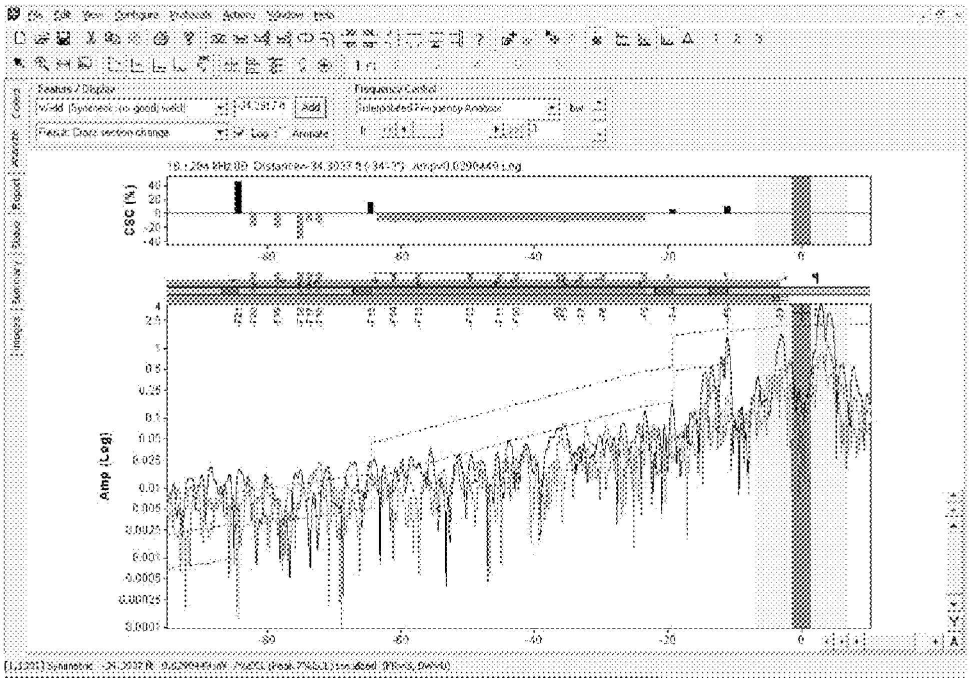

Figure G-9
Screen Response from a Buried Pipe Determined to Contain Thinning

G.5.2 Application

Guided waves can be used to detect wall thinning around the circumference of buried pipe, with access from a single excavation or location (Figures G-10 and G-11).

Once a location of wall thinning is identified (Figure G-12), the location may be excavated for more detailed direct measurements, for example with ultrasonic testing (UT).

Figure G-10
Guided Wave Inspection. ***Source Becht-Sonomatic, with permission***

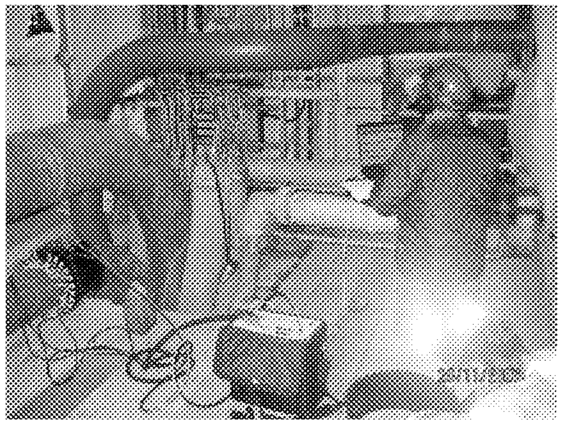

Figure G-11
Guided Wave Inspection. ***Source Becht-Sonomatic, with permission***

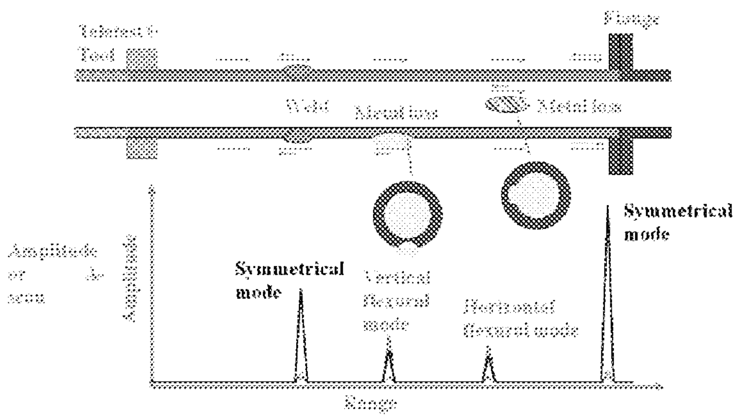

Figure G-12
Principle of Guided Wave Inspection. ***Source Becht-Sonomatic, with permission***

G.5.3 Limitations

When this report was prepared, the following limitations existed. However, guided wave technology is advancing rapidly and may eventually overcome some of these limitations. The key limitation is the effective range and sensitivity that guided waves can be reliably used. This is a function of a number of variables, some of which are listed below.

- Pipe coating, burial depth, backfill material and moisture content immediately surrounding the component can significantly attenuate guided wave energy.
- When guided wave energy is transmitted through a reducer or elbow, the energy is significantly distorted complicating data analysis. In some cases, the pipe cannot be adequately analyzed beyond such a component.
- Guided wave examinations cannot be conducted beyond a flange as the energy is reflected at the flange interface.

- The effective length of a guided wave examination is reduced when a component contains significant damage.
- Guided waves cannot determine actual remaining wall thickness. It provides an average wall thickness.
- Because the sensitivity and accuracy of guided wave depends on a number of parameters, the method is best used as a screening tool to locate areas for more refined inspections using direct examination tools such as UT.
- Guided waves cannot differentiate between inside and outside wall loss.
- Guided waves cannot precisely characterize reflector shape and size.

While not a limitation, application of guided wave technology for the examination of buried piping is relatively new and rapidly evolving. Data analysis is difficult. Each inspection application presents unique challenges that must be overcome. As such, examination personnel must be well trained and qualified.

G.6 Radiography

G.6.1 Description

Radiography uses the penetrating capabilities of a radiation source such as a gamma or X-ray to penetrate a component to perform volumetric examination. A radiation source is placed on one side of the component and a recording media such as film or phosphor plate on the other to record the amount of radiation that penetrates the component. Internal voids such as flaws or thinning result in a greater amount of radiation penetrating the component, which is recorded by the recording media. An illustration of this is provided in Figure G-13. The examiner interprets the image to identify density variations that are indicative of a damage mechanism. Radiography is especially sensitive to the detection of three-dimensional flaws such as internal voids, and less sensitive to planar flaws such as cracks.

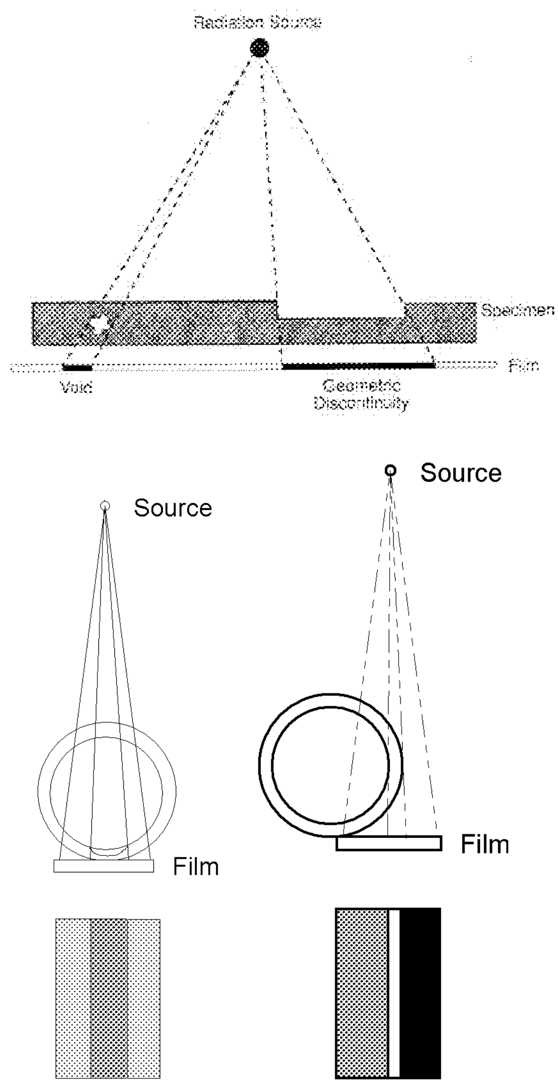

Figure G-13
Principle of Radiography of Pipe Wall

In order for the examination to be effective, the image must be of a certain quality. An image quality indicator such as a penetrameter is typically placed on the component and projected onto the recording media. The resulting image must be of a certain quality level, which is dependent on the purpose of the examination and typically specified in the examination procedure.

G.6.2 Application

Radiography can be used to detect and measure thinning as well as identify internal conditions. It is best suited to identify damage mechanisms such as preferential weld attack (Figure G-14) or pitting. Such thinning is typically identified by placing the detection medium in line with the pipe component such as shown in the left hand figure in Figure G-13. Thinning can be quantified to some degree by using a tangential technique where the source and the recording medium are aligned with the pipe wall as shown in the sketch on the right in Figure G-13. Wall thickness measurements are limited to those taken at that tangent location of the pipe. Radiography is also the preferred technique to detect internal deposits such as silt or tuberculation (Figure G-15). Radiography can also be used to evaluate internal piping component conditions. Examples include identifying the location and integrity of a gate within a valve.

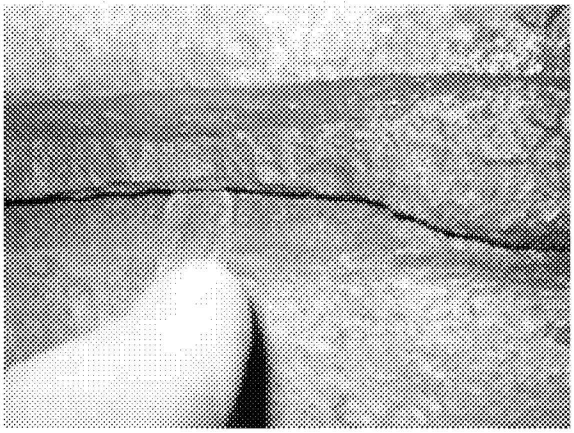

Figure G-14
Preferential Weld Attack

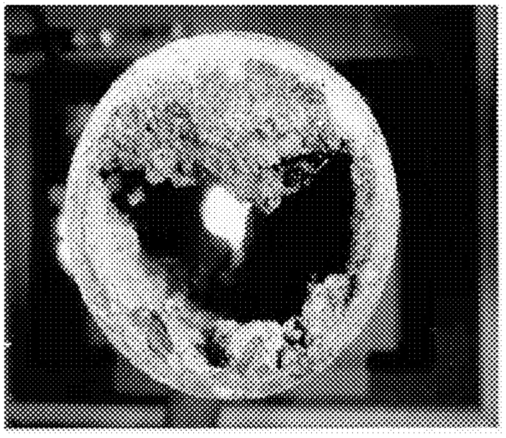

Figure G-15
Tuberculation

While radiography can be used to examine welds for service related cracking, ultrasonics are better suited for this application.

G.6.3 Limitations

- Radiation safety considerations are significant and require planning.
- Radiography is not sensitive to planar flaws.
- Localized inspection, examination is limited to the data collected on the recording media.

- Wall thickness measurements are very limited.
- Radiography requires access to the pipe's outside surface.
- Radiography is generally considered a qualitative rather then a quantitative technique.

G.7 Pulsed Eddy Current

G.7.1 Description

The Broadband Electromagnetic Method (BEM) can be used to perform spot thickness measurements inside buried piping. The method has been applied for assessing the condition of bell-and-spigot joints in power plants (reference 112). However, in principle, the technique can be used to perform thickness measurements anywhere.

The method applies the pulsed eddy current process to probe the pipe condition at a given location while using proprietary software to infer the wall thickness value. In so doing, the method is a variant of the Incotest technique currently used to examine aboveground insulated pipes and vessels (reference 113). The BEM sensors, however, are better designed for deployment in the dirty below ground environment. The pulsed eddy current probing requires the sensor to be stationary during acquisition. To speed up the deployment, BEM uses linear sensor arrays with up to 6 coils to increase the areal coverage per measurement. In addition, a drum-styled tool that includes multiple linear arrays to obtain full circumferential coverage is also available to further facilitate below ground piping examinations.

G.7.2 Application

The pulsed eddy current process used by BEM detects the presence of defects by inducing eddy currents on the outside surface of the pipe and monitoring the change in the magnetic field as the currents diffuse and permeate the pipe. The average wall thickness over the footprint of the probe is then measured by recording the time it takes for the currents to diffuse and permeate the pipe wall and comparing it with calibration standards. When performing measurements in contact with the pipe, the areal coverage is approximated by the size of the coil. However, as the coil is lifted away from the pipe, the footprint increases significantly affecting the spatial resolution of the method (reference 113).

The BEM advantages for buried pipe condition assessments include:

- The probe requires no contact with the pipe.
- It is not affected by the pipe curvature.
- It is not affected by the presence of coatings or silt deposits.
- It is tolerant of lift-off.
- It is tolerant of probe misalignment and rocking.
- It is tolerant of the operator skill level.

G.7.3 Limitations

- Lift-off will affect the spatial resolution.
- The method may underestimate wall loss.
- Areas of localized damage may be missed.
- It may require recalibration at various pipe joints.

G.8 In-Line Inspection

G.8.1 Description

In-line inspection (ILI) tools (also called intelligent pigs in the oil and gas pipeline industry) are either flow-driven or tethered devices, launched at one end opening of a pipeline and collected at the other end, Figure G-16 (references 65, 66). Between these two end points, the ILI tools collect wall thickness readings all around the pipe circumference, which are stored on on-board computers and downloaded when the tool is retrieved.

The ILI wall thickness inspection options are:

- Magnetic flux leakage (MFL).
- Ultrasonic testing (UT).
- Remote field eddy current.

This ability of the ILI tool to measure wall thickness over the full length of pipe and 360° around is unmatched by the other inspection techniques.

Use and development of ILI tools in power plant applications are discussed in references 114 and 115.

G.8.2 Limitations

- The ILI tool must be able to negotiate bends, changes in pipe size, valves and branch openings without getting stuck. This often makes it impractical for use on buried lines that were not explicitly designed to accommodate the ILI tool.
- The inner wall of the pipe must be cleaned before running the ILI tool. This is achieved through multiple runs of cleaning pigs that scrub the pipe.
- In the case of MFL and UT, the ILI tool transducers must be in contact with the pipe ID.
- The pipe must be equipped with a launcher and a receiver for the tool.

Figure G-16
Launcher for Small-Diameter ILI Tool

G.9 Hydrotest

G.9.1 Description

Pressure decay is a test method recognized in ASME Section XI (reference 70), IWA-5244(b), which states: "The system pressure test for buried components that are isolable by means of valves shall consist of a test that determines the rate of pressure loss. Alternatively the test may determine the change in flow between the ends of the buried components. The acceptable rate of pressure loss shall be established by the Owner."

The pipe is filled with water (with proper isolation and fill-venting procedure). The water-filled section is slowly pressurized to a pre-calculated pressure, not to exceed the yield stress of the piping system. The pressure is then monitored over a period of time for evidence of pressure decay that would indicate a leak.

An alternative hydrotest technique consists in purposely bursting the corroded pipe sections by hydrotest while the system is out-of-service. Such a destructive test was commonly used on pipelines before the advent of in-line inspection technology (ILI, intelligent pigs). It is also possible to back-calculate the size of corrosion zones (depth and length) that would survive such a hydrotest. This concept underpins the criterion for flaw evaluation in ASME B31G (reference 71). API RP 1129 (reference 25) illustrates this approach: "Hydrostatic testing used in combination with other inspection methods can provide an indication of the overall pipeline condition with excellent assurance of integrity." 49 CFR 195 (reference 72) defines the minimum test requirements to be at least a 4-hour continuous period at 125 percent or more of MOP [maximum operating pressure] with an additional 4 continuous hours at 110 percent of MOP for pipelines that are not visually inspected for leakage.

G.9.2 Limitations

Hydrotest to failure has obvious shortcomings that render the method impractical in most cases. These include:

- It is a destructive method that relies on bursting severely corroded sections.
- It requires the line to be out-of-service and water-filled.
- It requires leak tight isolation valves or temporary isolation (such as freeze plug or stopple).
- It does not pinpoint the source of leak.
- It may require correction for temperature variation if part of the line is aboveground.

H
CORROSION MONITORING FOR BURIED PIPES

H.1 Electrical Resistance Corrosion Probes

Electrical resistance (ER) corrosion probes are used to measure ID or OD corrosion rates. The probe resistance increases as it corrodes and loses metal (reference 67). ER soil corrosion probes are a good tool to determine if sufficient corrosion prevention is being achieved on the pipe. Flat probes can be used against the pipeline, under tape wrap.

For the first year, data is typically collected on a monthly basis until a corrosion rate can be established, after which data can be taken quarterly.

H.2 Corrosion Coupons

Well characterized metal specimens are inserted into the flow stream and weighed at regular intervals to measure corrosion-erosion loss (reference 67). Coupons from weight loss experiment are also examined visually for evidence of pitting. Pitting can then be characterized qualitatively or quantitatively (reference 68).

H.3 Linear Polarization Resistance

Linear polarization resistance (LPR) is a method for measuring corrosion rates by measurement of current and potential (reference 69).

I

FITNESS-FOR-SERVICE ASSESSMENT TECHNIQUES

There are several methods for the assessment of wall thinning and cracking in piping systems, but they do not address burial loads. Table I-1 is a summary of fitness-for-service assessment methods. Plants should follow their existing procedures and commitments regarding fitness-for-service assessments (reference 117), but also account correctly for loads specific to buried pipes, as explained in this Appendix.

Table I-1
Methods for FFS Assessment

ASME	Reference	Safety Related	Pressure	Soil Loads	Other Loads
ASME XI	81, 82	Yes	Yes	No	Yes
CC N-597	74, 75	Yes	Yes	No	Yes
CC N-513	75, 76	Yes	Yes	No	Yes
B31G	71, 72, 77, 78	No	Yes	No	No
FFS-1/API579	80	No	Yes	No	Yes

I.1 Wall Thinning

I.1.1 Safety-related Systems

I.1.1.1 Code Case N-597-2

The rules of ASME Code Case N-597-2 apply to the evaluation of Class 1, 2 and 3 piping systems subject to internal or external wall thinning (reference 74), Figure I-1.

The assessment should consider the NRC's conditions of acceptance, as stated in Regulatory Guide 1.147 (reference 75), and quoted hereunder:

"(1) Code Case must be supplemented by the provisions of EPRI Nuclear Safety Analysis Center Report 202L-R2,"Recommendations for an Effective Flow Accelerated Corrosion Program" (Ref. 6), April 1999, for developing the inspection requirements, the method of predicting the rate of wall thickness loss, and the value of the predicted remaining wall thickness. As used in NSAC-202L-R2, the term "should" is to be applied as "shall" (i.e, a requirement).

(2) Components affected by flow-accelerated corrosion to which this Code Case are applied must be repaired or replaced in accordance with the construction code of record and Owner's requirements or a later NRC approved edition of Section III, "Rules for Construction of Nuclear Power Plant Components," of the ASME Code (reference 12) prior to the value of tp reaching the allowable minimum wall thickness, t_{min}, as specified in -3622.1(a)(1) of this Code Case. Alternatively, use of the Code Case is subject to NRC review and approval per 10 CFR 50.55a(a)(3).

(3) For Class 1 piping not meeting the criteria of -3221, the use of evaluation methods and criteria is subject to NRC review and approval per 10 CFR 50.55a(a)(3).

(4) For those components that do not require immediate repair or replacement, the rate of wall thickness loss is to be used to determine a suitable inspection frequency so that repair or replacement occurs prior to reaching allowable minimum wall thickness, t_{min}.

(5) For corrosion phenomenon other than flow accelerated corrosion, use of the Code Case is subject to NRC review and approval. Inspection plans and wall thinning rates may be difficult to justify for certain degradation mechanisms such as MIC and pitting."

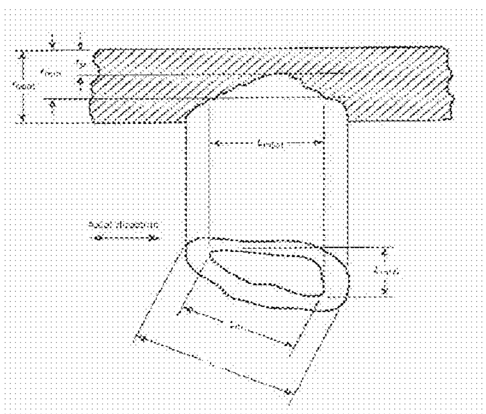

Figure I-1
Corroded Area (Figure 3622-2 of Code Case N-597-2)

I.1.1.2 Code Case N-513

The rules of ASME Code Case N-513 (reference 76), apply to the evaluation of flaws in moderate energy lines ($T \leq 200^{\circ}F$ ($93^{\circ}C$) and $P \leq 275$ psi (1.9 MPa)) in Class 2 or 3 piping. The rules for non-planar flaws apply to wall thinning.

The assessment should consider the NRC's conditions of acceptance, as stated in Regulatory Guide 1.147 (reference 75), and quoted hereunder:

"(1) Specific safety factors in paragraph 4.0 must be satisfied.

(2) Code Case N-513 may not be applied to:

(a) Components other than pipe and tube.

(b) Leakage through a gasket.

(c) Threaded connections employing nonstructural seal welds for leakage prevention (through seal weld leakage is not a structural flaw; thread integrity must be maintained).

(d) Degraded socket welds"

Important points to keep in mind when applying Code Cases N-597 and N-513:

- The assessment is based on a thickness, t_p, which is the current measured thinnest area minus the future loss to the next inspection.
- The assessment addresses pressure loads (hoop stress) as well as other applied loads, but loads unique to buried pipes are not addressed explicitly.
- In the case of buried pipes, loads other than pressure include soil and surface loads, constrained thermal effects, ground settlement, seismic wave passage, etc. An example of such assessment is provided in NUREG/CR-6876 (reference 7). The NUREG should only be used after it has been thoroughly studied and understood, as it contains assumptions and limitations which may not be applicable to the piping system being evaluated.
- In addition to the limits imposed in Code Cases N-597 and N-513, it is recommended to verify that t_p is not less than 0.10 inch, to prevent a pinhole leak.

I.1.1.3 Future Wall Loss

For cases of wall thinning, and in the absence of line specific data, the predicted thickness can be estimated by either:

1. Use of the average rate of wall thinning from date of installation to the date of measurement:

$$\text{Rate} = (t_{initial} - t_{current}) / \text{time}$$

   Where:

   $t_{initial}$ = initial thickness of pipe, nominal can be used if unknown.

   $t_{current}$ = wall thickness from current measurement.

   time = time from date of installation until current.

   It should be cautioned that the above formula is limited to degradation mechanisms that have roughly linear rates of wall loss with time. It is not conservative for mechanisms that have long incubation times before damage begins.

2. Use of published industry rates of the same material in similar conditions (e.g., reference 87).

I.1.2 Non-Safety-related Systems

The same assessment methods as safety-related systems may be applied. In addition, the following methods may be considered.

I.1.2.1 ASME B31G

For decades ASME B31G (reference 71) has been the tool commonly used to evaluate wall thinning in oil and gas pipelines, using the results of in-line inspection (ILI, intelligent pigs). The method has been distilled down to simple go / no-go criteria based on the length and depth of wall thinning. More recent variants to ASME B31G, based on procedures such as RSTRENG (references 77, 78) and on international codes (reference 79) are being introduced as alternatives in the new edition of ASME B31G, to be issued.

Without a clear understanding of its technical basis and its limitations, ASME B31G can be misapplied. The limitations of ASME B31G are listed in the document itself, and quoted hereunder:

"(a) This Manual is limited to corrosion on weldable pipeline steels categorized as carbon steels or high strength low alloy steels. Typical of these materials are those described in ASTM A 53, A 106, and A 381, and API 5L. (The current API 5L includes all Grades formerly in MI 5LX and 5LS).

(b) This Manual applies only to defects in the body of line pipe which have relatively smooth contours and cause low stress concentration (e.g., electrolytic or galvanic corrosion, loss of wall thickness due to erosion).

(c) This procedure should not be used to evaluate the remaining strength of corroded girth or longitudinal welds or related heat affected zones, defects caused by mechanical damage, such as gouges and grooves, and defects introduced during pipe or plate manufacture, such as seams, laps, rolled ends, scabs, or slivers.

(d) The criteria for corroded pipe to remain in service presented in this Manual are based only upon the ability of the pipe to maintain structural integrity under internal pressure. It should not be the sole criterion when the pipe is subject to significant secondary stresses (e.g., bending), particularly if the corrosion has a significant transverse component.

(e) This procedure does not predict leaks or rupture failures."

It is also important to understand what "passing B31G" means:

"(a) Any corroded region indicated as acceptable by the criteria of this Manual for service at the established MAOP is capable of withstanding a hydrostatic pressure test that will produce a stress of 100% of the pipe SMYS.

(b) Any corroded region indicated as acceptable for service at a reduced MAOP is capable of withstanding a hydrostatic pressure test at a ratio above the MAOP equal to the ratio of a 100%

SMYS test to 72% SMYS operation. If a larger ratio is desired, the reduced MOP can be adjusted accordingly."

These are parameters unique to oil and gas pipelines, and may not be advisable or desired for buried water lines in nuclear power plants.

I.1.2.2 API 579 / ASME FFS-1

The fitness-for-service assessment methods of API 579 / ASME FFS-1 are well structured, and presented in a step-by-step format (reference 80). Note that the method of API 579 / ASME FFS-1 is different from ASME XI or NRC approved assessment methods (reference 117), and should not be applied to safety-related piping systems. The API 579 / ASME FFS-1 chapters applicable to the FFS assessment of wall thinning are Chapter 4 (general corrosion), Chapter 5 (local thin area), and Chapter 6 (pitting). The method should be applied in all its detail, with due consideration to limits of applicability. As a broad overview, the limits on wall thinning are intended to prevent two failure modes: leakage and burst. In simple terms (recognizing that the full assessment is more detailed than the formulas given here) the prevention of leakage and burst is achieved through the following checks:

(a) Prevention of leakage is achieved by placing a limit on the thinnest spot, in the general form:

$$t_{mm} - FCA \geq 0.1 \text{ in}$$

t_{mm} = minimum measured wall thickness, from inspections.

FCA = future corrosion allowance, projected from inspections.

(b) Prevention of burst is achieved by placing a limit on a thickness averaged through the thin area, in the general form:

$$t_{am} - FCA \geq RSF_a \, t_{min}$$

t_{am} = average of measured wall thicknesses at and around worst spot, over a calculated length.

RSF_a = allowable remaining strength factor, an allowed reduction in design code safety factor.

t_{min} = minimum required wall thickness for all operating loads, including pressure, soil and surface loads, thermal effects, seismic loads, etc.

To further prevent burst, an additional margin is imposed in the form of a limit such as:

$$t_{mm} - FCA > t_{min} / 2$$

I.2 Cracking

I.2.1 Safety-related Systems

The evaluation of cracks or crack-like flaws for safety-related piping systems is addressed in ASME Section XI Non-mandatory Appendices C and H (references 81, 82). As an alternative, the rules of Code Case N-513 (reference 76) for planar flaws can be used, with the limitations described above for moderate energy lines.

There are two main challenges in the assessment of crack-like flaws:

- The material properties required for the assessment (fracture toughness, weld residual stresses, etc.) are usually difficult to obtain, although conservative bounding values can be assumed.
- The prediction of crack size at the next inspection interval, and hence the prediction of crack growth rate, is difficult.

I.2.2 Non-Safety-related Systems

The failure assessment diagram method of Chapter 9 of API 579 / ASME FFS-1 (reference 80) provides a good step-by-step description of the FFS evaluation procedure for crack-like flaws. It is similar to ASME Section XI Appendix H, but with different options for safety margins. Both methods stem in part from British Standard BS 7910 (reference 83).

The same two difficulties as for safety-related systems apply (material properties and crack-growth estimate).

I.3 Leak-Before-Break

Leak-before-break (LBB) is an extension of the analysis of crack-like flaws. In summary, the LBB method consists in postulating a through-wall crack, large enough to be detected, and checking whether such a crack would be stable. In other words, would it leak and be detected well before it propagates into a large break? This assessment needs to be performed with several safety factors to assure a safely conservative result, following the NRC Regulatory Guide 0800 Standard Review Plan (reference 84). In particular:

- "[LBB is applied] to eliminate from the design basis the dynamic effects of pipe ruptures …"
- "[it applies to] Class 1 and 2 … other piping will be considered"
- "Unless a detailed justification can be presented that accounts for the effects of these sources of uncertainties, a margin of 10 on the leakage prediction will be required for determining the leakage size flaw."
- "[The pipe should exhibit] no risk of brittle fracture"

The key points concerning the LBB fracture mechanics analysis include:

- Through-wall flaw postulation.
- Margin of 2 between leakage crack and critical crack size.
- The load combinations applied to the postulated crack are 1.4 x normal operating loads + SSE, or 1.0 x absolute sum normal loads + safe shutdown earthquake (SSE).
- The material and weld properties may be archival material data or industry generic lower bounds.
- More detailed guidance will be provided in the FFS assessment report, being developed separately.

I.4 Mechanical Damage

Mechanical damage in buried pipes can take several forms. The three most common are buckling, dents and gouges.

I.4.1 Buckling

Buckling of buried pipes can occur as a result of large ground movement, such as a landslide. There are two failure modes associated with buckling:

- Break by formation of a crack at the buckle itself, or opposite to the buckle (high tensile stress), Figures I-2 and I-3.
- Reduction in flow area.

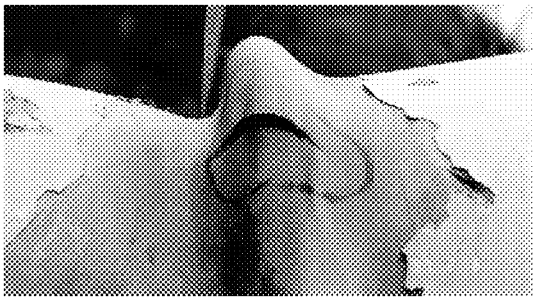

Figure I-2
Fracture at Buckle

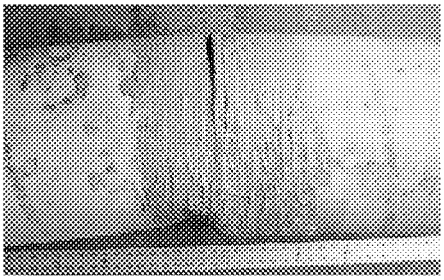

Figure I-3
Tensile Fracture Opposite Buckle

The effect of buckles on the mechanical integrity of buried and subsea oil and gas pipelines has been studied extensively, and predictive equations have been developed, based on the bending strain in the metal (references 85, 86). In all cases when large ground movement or settlement has taken place, where there is a risk of buckling, the pipe should be unearthed, inspected and repaired as necessary.

I.4.2 Dent and Gouge

A dent is a local deformation of the round cross-section of the pipe. It could happen at the bottom of the pipe if a pipe with a large D/t ratio (diameter over thickness) is bearing down on a rock, or at the top of the pipe if the pipe is accidentally impacted by excavating equipment. There are three outcomes to a dent-forming impact:

- An immediate puncture causing a leak.
- No damage beyond the dent itself. This is usually the case for dents in pipes with small D/t, for example a dent in a 4” sch.40 pipe (D/t = 4.5/0.237 ~ 20).
- A delayed rupture. This is the case for unconstrained dents in relatively large D/t pipes, operating at a high hoop stress (PD/(2t) in the order of 1/2 of yield, where P = operating pressure, D = diameter, t = wall thickness), and subject to pressure fluctuations. Such a high operating hoop stress is rare for buried pipes in power plants, but common in oil and gas pipelines where dents, detected by caliper tool runs, are often critical and require immediate repair.

A dent can be accompanied by a gouge (a knife-like mark of the metal surface) if the impact was by a sharp object.

I.5 Occlusions

Occlusions can cause several detrimental effects:

- Accelerated crevice corrosion and microbial corrosion underneath the deposits, which should be evaluated as wall thinning.
- A reduction in flow area. Given the flow characteristics, the assessment of flow reduction can be performed following standard pressure drop calculations.
- Debris carried downstream, potentially damaging equipment and components, should be evaluated on a case-by-case-basis.

J
LEAK DETECTION AND ISOLATION

J.1 Leak Detection

The repair of a buried pipe is typically dictated by one of two considerations:

- The pipe has failed and needs immediate repair.
- Direct inspections and fitness-for-service assessment have concluded that the pipe needs to be repaired before failure is reached.

In the first case, when the pipe has failed, most often by leakage, an immediate challenge is to detect the source of the leak. Leak detection should be performed under the following conditions:

- Loss of pressure.
- Evidence of tritium or other contaminants in the ground water.
- Evidence of tritium plume.
- Surface wetness that is suspected to result from leakage from buried pipes.

Leak detection can be performed using any of the following methods.

- Leak monitoring wells
- Tracer gas
- Acoustic signal
- Dyes

J.1.1 Monitoring Wells

J.1.1.1 Description

A borehole is drilled in the earth and lined, either partially or entirely, with a casing to stabilize and isolate one or more sections of the borehole. Monitoring wells, like investigation wells, are used to collect environmental media for examination and testing. However, unlike investigation wells, monitoring wells are intended to be in service longer (typically years) to allow continued sampling of groundwater or soil gas. Further information can be found in references 8 and 9.

J.1.1.2 Application

- Monitoring of radionuclides (e.g., tritium) in the groundwater and aquifer.
- Monitoring of other contaminants in the ground water (e.g., fuel oil, lube oil, solvents, etc).
- Evaluation of constituents can help identify source of the leak and extent of contamination.

J.1.1.3 Limitations

- Does not indicate the location of the leak.
- Generally will not detect leaks of raw or pure water.
- Data from plants with significant changes to groundwater levels (e.g., tidal action) can be difficult to interpret.

J.1.2 Tracer Gas

J.1.2.1 Description

A tracer gas leak test is used to pinpoint the source of a leak. Volatile tracer gases are introduced into the liquid-filled pipe. A portable probe, or a series of fixed probes, can be used to analyze the ground surface for signs of tracer vapors that would indicate a leak. Typical tracer gases that are added to liquids include helium and hydrogen.

J.1.2.2 Application

- Use of tracer gas permits a long pipeline to be tested at one time, between isolation points.
- The pipeline can be filled and in-service during the test.
- The location of a leak along a pipeline is clearly marked by the location of the tracer.
- Depending on the conditions, liquid leaks as small as 0.1 gallon per hour (0.4 L/hour) can reportedly be detected (reference 120).

J.1.2.3 Limitations

- The backfill must have some degree of air permeability to let the gas seep to the surface.
- If the pipe is under a concrete mat, probes have to be installed in holes dug through the concrete.
- The leak source may be difficult to locate if the pipe is under a concrete mat.
- The tracer gas may not be compatible with the pipe material.
- The tracer gas may not be compatible with the system and its equipment.

J.1.3 Acoustic Signal

J.1.3.1 Description

Acoustic leak signals are commonly used to detect water leaks in waterworks and buried fire water lines. Leaks can be detected and leak locations can be pinpointed by connecting hydrophones, low frequency vibration detectors, or accelerometers to the pipe or to a metallic extension to the pipe, Figure J-1.

J.1.3.2 Application

- The leak can be detected in service.
- There are no tracers that need to be added to the fluid.
- The location of a leak along a pipeline is clearly identified by the sensors.

J.1.3.3 Limitations

- The method may not detect very small leaks.
- Sensors need to be installed on the pipe at regular intervals.

J.1.4 Dyes

J.1.4.1 Description

Dyes are added to the flowing water, and leaks are detected by inspection for dyed water at the ground surface. Dyes can be fluorescent and detectable with UV lamps. Dye can also pinpoint a leak source under water, Figure J-2.

J.1.4.2 Application

- A long pipeline can be tested at one time.
- The pipeline can be filled and in-service during the test.
- The location of a leak along a pipeline is indicated by the dye color at the surface.

J.1.4.3 Limitations

- The backfill must be permeable to permit the dye to reach the surface.
- Surface dye may not indicate the exact leak location since the leak may migrate through soil.
- Small leaks are not readily detected.
- The dye may not be compatible with the pipe material.

- The dye may not be compatible with the system and its equipment.

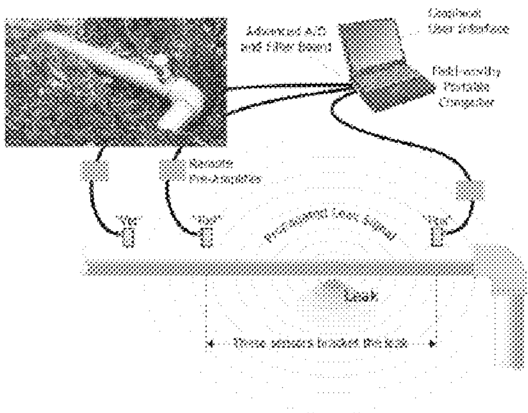

Figure J-1
Leak Detection System

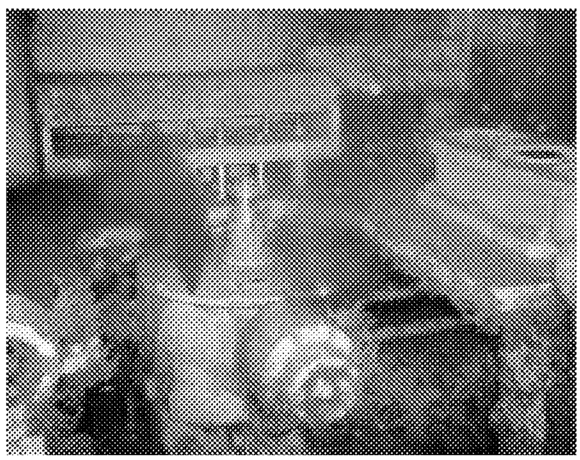

Figure J-2
Dye Locates Leaks Underwater

J.2 Leak Isolation

J.2.1 Flow Isolation

J.2.1.1 Description

If the line contains an upstream isolation valve, and if the conditions of operation permit, the leaking pipe can be isolated by closing the upstream valve.

J.2.1.2 Application

Closure of an isolation valve is the preferred technique to isolate the segment.

J.2.1.3 Limitations

- Flow isolation is only feasible if there is an isolation valve in the line, and if the valve is leak tight.
- The fluid will continue to leak for a while after closure of the isolation valve till the pressure drops downstream of the isolation valve to atmospheric pressure.

J.2.2 Freeze Plug

J.2.2.1 Description

If the flow in the line can be interrupted but the section to be repaired cannot be drained, the line may be freeze plugged upstream and downstream of the leak site, then the section between freeze plugs can be drained and repaired, Figure J-3 (reference 91).

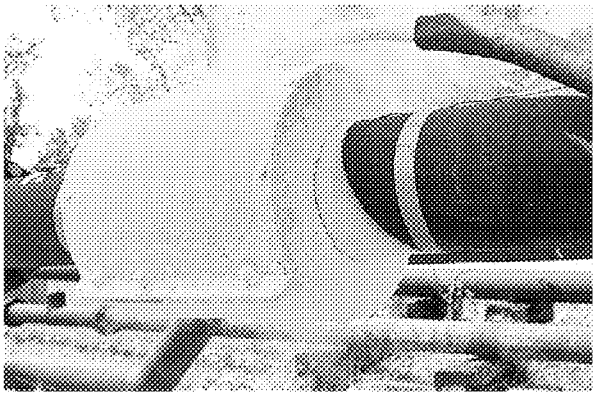

Figure J-3
Freeze Plug with Liquid Nitrogen

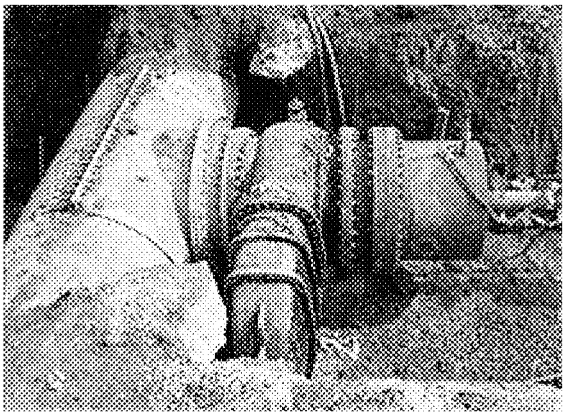

Figure J-4
Tapping In-service in a Water Line

J.2.2.2 Application

Freeze plugs have been commonly used to isolate liquid-filled segments of pipe in the absence of an isolation valve, even in high pressure applications (hundreds of psi).

J.2.2.3 Limitations

- Making a freeze plug requires experienced technicians and qualified procedures.
- The flow must be interrupted in the line to permit the ice plug to form.
- The procedure must be implemented with know-how to prevent failing the pipe at the plug or between plugs due to ice expansion.
- The fluid will continue to leak for a while after freeze plugging till the pressure drops downstream of the plug to atmospheric pressure.

J.2.3 Wet Tap

J.2.3.1 Description

A plug can be inserted into the line through a manhole, or in-service by wet tapping and insertion of a plug, Figure J-4. A hole is cut through the top or the side of the pipe, a gate valve is connected to the opening, and a plug (a stopple) is inserted through the tapping valve into the pipe to stop flow.

J.2.3.2 Application

Wet tapping is common in the water works and oil-gas pipeline industries (in the latter case it is called hot tapping). The procedure is often performed with the line flowing, in service.

J.2.3.3 Limitations

- Wet tapping requires experienced personnel, specialized tapping machines, and qualified procedures.
- The fluid will continue to leak for a while after insertion of the stopple by wet tapping till the pressure drops downstream of the isolation valve to atmospheric pressure.

K
REPAIR METHODS

K.1 Welded Repairs

K.1.1 Pipe Replacement

Replacement may be the most costly and time consuming option when dealing with degraded buried piping. However, in some cases it may be clearly the best option for long-term performance or where licensing issues need to be addressed. Replacement also provides the ability to upgrade materials and system features.

A common repair is to cut out and replace the corroded section of pipe. In this case, flow in the line will have to be interrupted, the line drained and then cut. An option to maintain flow is to install a bypass line using wet tapping to permit the main line to be replaced without service interruption.

K.1.2 Fillet Welded Patch

Pin-hole leaks are often repaired by fillet welding a patch or a pipe cap on top of a thinned or degraded component (Figure K-1). The patches are generally of the same material as the component and are formed to closely its shape. The welded patch has to be sized for the design pressure and its design life has to be established taking into consideration the potential for accelerated crevice corrosion by the water trapped between the patch and the pipe.

The fillet weld needs to be applied using a qualified welding procedure. Depending upon the material and its thickness, post weld heat treatments may be required by the construction or repair code.

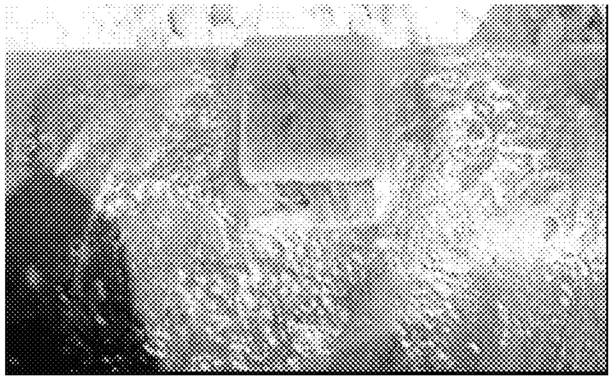

Figure K-1
Fillet Welded Patch Repair of an Excavated Buried Steel Pipe

K.1.3 External Weld Overlays

Exterior weld overlays are an effective repair method to address wall thinning or other degradation mechanisms. The overlay may be full-encirclement or localized. Full encirclement overlays are an excellent option to repair wall thinning and are even approved in some applications to repair cracking. One benefit of a full encirclement overlay is the ability to apply them with automated welding systems.

Overlays may also be applied locally to repair specific areas of degradation, such as pitting or MIC damage. Localized overlays are suitable to repair individual or multiple local degradation sites with the benefit of limiting the amount of welding required to complete the repairs.

One major benefit of all overlays is that they can provide a permanent repair solution along with full structural reinforcement of the piping. ASME Section XI has specific rules for the use of overlays to repair low to moderate energy Class 2 and 3 piping (references 93 to 96). Overlays have been successfully used on all classes of piping and for a wide range of materials.

K.1.4 Structural Inlays

Structural inlays are an effective method to address replacement of wall loss in piping systems that have suffered degradation from general corrosion or other damage mechanisms. Inlays are applied by first cleaning the surface of oxidation or other surface contamination that will impede welding. Then weld metal is applied to build up the surface, restoring the thickness of the component. In many cases, a matching filler metal will be used but enhanced materials may also be used to improve resistance to corrosion and future degradation. This should be carefully evaluated to prevent the creation of corrosion cells that may accelerate damage elsewhere.

When a welding procedure is used, qualified under ASME Section IX, structural inlays will generally meet the requirements for Code repairs under ASME rules and for most other Codes of Construction.

K.1.5 Corrosion Resistant Cladding

Corrosion-resistant cladding (CRC) is one of the very effective methods to prevent corrosion of sensitive areas in piping or in complete piping systems. Clad piping is available for installation, but on-site cladding may be applied to address specific components that may require cladding. A layer of corrosion resistant material is applied by welding to provide a high quality, permanent surface. Piping manufacturers may apply the cladding by use of roll bonding or explosive bonding methods which also provide permanent resistance to corrosion. Installation of clad piping requires special methods to perform the weld root to maintain corrosion resistance. The exterior, structural portion of the pipe is typically mild steel which is readily welded and can be easily installed.

K.1.6 Butt-welded Insert Plates

Butt-welded (or flush) insert plates are intended to restore the degraded component to a nearly new condition by replacing a section of degraded material with a like section. Most often used for repair of vessels, flush-plate repairs require removal of the degraded section, forming of a new panel/patch to fit into the area and then installation by flush butt-welding. The material may be modified (clad or change in base metal chemistry) to improve service life if a specific degradation mechanism has been identified. Because of the difficulties in bending and aligning small plates for flush butt welding, this repair method is common for large tanks and vessels, feasible for large pipe, several feet in diameter, but it is of limited use for smaller pipe.

Since there is no change in design, butt-welded insert plates will generally meet the requirements for Code repairs under ASME rules and for most other Codes of Construction. The welding procedure should be qualified under ASME Section IX,

K.1.7 Welded Sleeve

Full encirclement reinforcement sleeves consist of two tight-fitting cylindrical shells clamped around the pipe section to be repaired and then welded along the two longitudinal seams (Figure K-2). The Type A sleeve is only welded longitudinally but is not welded circumferentially to the primary pipe and is not capable of containing a leak but functions as pressure reinforcement for a thinned area. The Type B sleeve is like the Type A sleeve, but is also welded circumferentially to the host pipe and is designed to contain a leak at full system pressure. These are suitable for repair of leaking defects or defects that may eventually leak. They can also be used to structurally reinforce a degraded pipe to keep it in service.

Such tight-fitting sleeves are necessary for oil and gas transmission pipelines that operate at high hoop stress, but are not needed to repair water or process lines operating at hoop stresses below approximately one-half the yield strength of the metal.

If designed in accordance to Code of Construction rules and installed using qualified procedures, a Type B full-encirclement sleeve may meet Code requirements and be suitable for extended service.

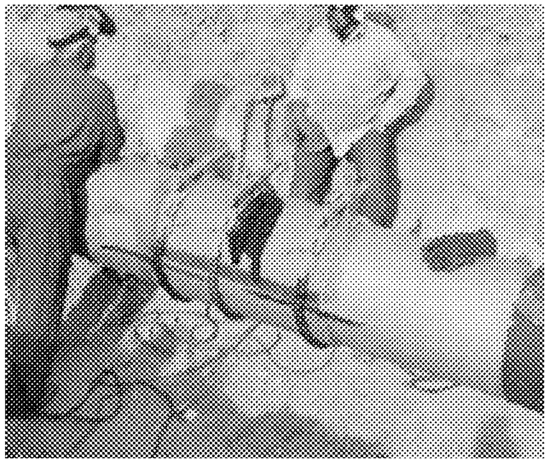

Figure K-2
Welded Sleeve Repair

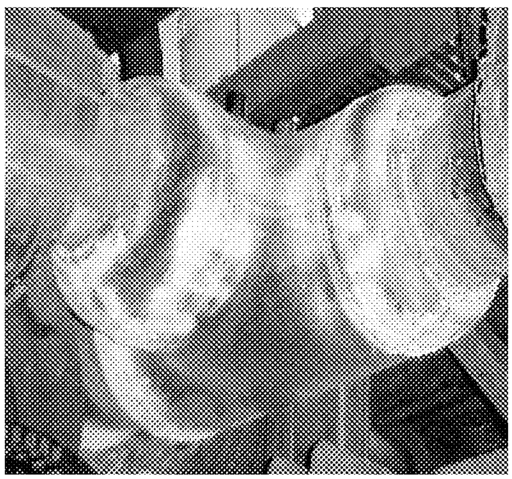

Figure K-3
Leak Box Welded Around a Tee

K.1.8 Leak Box

In this case, the pipe is uncovered and a pipe larger than the leaking pipe with a set of matching pipe caps are split in half, positioned around the pipe and welded to form a sealed box around the degraded section, Figure K-3. The box is equipped with a vent and a drain, and may be welded while the line is in service.

Similar to the full-encirclement sleeve, if the leak box is designed in accordance with Code of Construction rules and installed using qualified procedures, a leak-box may meet Code requirements and be suitable for extended service.

K.1.9 Peening and Welding

One method to seal a small pin-hole is to use peening to close the leak and then welding to seal it. For more significant leakage, welding is used first to deposit additional material around the pinhole and then use peening to seal the leak. Pin-hole type leakage combined with wall thinning can be sealed using this method as well, but in this case the welding heat input needs to be reduced to avoid burn-through. After sealing, other repair methods such as overlays may be used to provide a permanent solution (reference 92).

K.1.10 Pipe Cap

A standard ASME B16 pipe cap may be welded to the pipe to cover a pinhole leak.

K.2 Non-Welded Repairs

K.2.1 Insertion Techniques

K.2.1.1 Inverted Liner

The insertion of an inverted liner is a common repair technique in waterworks for metallic as well as concrete pipe. Two access points are established, by dig or at manholes, which encompass the corroded area. The pipe is opened at these two access points and a liner is inserted at one end and inverted by hydrostatic pressure to the other end. The inverted pipe is cured in-place, becoming a new corrosion-resistance liner inside the corroded host pipe. Questions associated with the use of this technique in safety-related applications, such as seismic qualification, are unresolved (reference 23).

K.2.1.2 Slip-Lining

Piping degraded by wall thinning, erosion, pitting and other mechanisms can be repaired by use of composite or high density polyethylene (HDPE) slip-liners. Slip-lining is probably the simplest of the available lining options. It involves slipping a new pipe inside another generally older, larger pipeline. GRP and PVC have also been used as slip liners.

Coiled or butt-welded HDPE pipes are well suited to this technique since they form long coiled liners, butt fused end-to-end. The flexibility of HDPE allows it to be pulled into place, including through large radius bends.

Slip-liners are installed by removal of a pipe fitting or section at one end and installation of the liner by slipping it into the degraded pipe section. The HDPE liner is shipped to the site in a collapsed U-shape, inserted by pulling through the host pipe, then inflated back to a round shape. The liner does reduce the pipe ID slightly but at the same time it reduces the flow coefficient of friction. On balance the slip-liner will typically have no adverse effect on flow rate.

K.2.1.3 Internal Seals

For large pipe, where man entry is possible, a cylindrical rubber liner can be inserted in a particular section to locally arrest corrosion and bridge leak sites. A metal band is commonly used to wedge the liner in place.

K.2.2 Mechanical Clamp

A mechanical clamp consists of half-cylinder clamps placed around the degraded section of pipe and bolted together. Leak tightness can be provided by one of two means:

- Sealant injection through nozzle ports placed around the clamp, Figure K-4.
- Without sealant injection, by means of a preloaded O-ring gaskets along the circumference of the clamp.

The repair can be installed on-line with water leaking from the pipe. Mechanical clamps are covered in ASME Section XI, Appendix IX (reference 97).

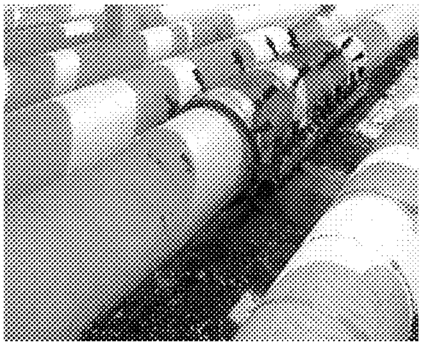

Figure K-4
Mechanical Clamp with Sealant Injection Ports

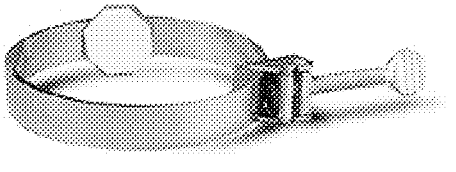

Figure K-5
Leak Strap

K.2.3 Threaded Repairs

This repair involves drilling a hole into the pin-hole leak area to provide clean metal for threading. The hole is then threaded, and an epoxy or sealant coated screw is screwed in position.

K.2.4 Leak Strap

One type of clamp is a leak strap, which is then wrapped with a fiberglass tape coated with a water-activated resin, Figure K-5.

K.2.5 Wrap Repairs

Non-metallic composite pipe repair is an effective method to repair degraded piping by using a composite fabric made of a fiber impregnated with a high strength adhesive. Typical fibers used include fiberglass, aramid, or carbon fiber. The repair is made by wrapping or covering the degraded area with several layers of composite, which then cures to provide a permanent bond, Figure K-6. Multiple layers are used to achieve appropriate thickness and strength to meet pressure boundary requirements.

The ASME Post-Construction standard PCC-2 (reference 88) has a detailed design and repair standard to address the implementation of this type of repair. The repair has not been submitted for regulatory review for safety-related applications.

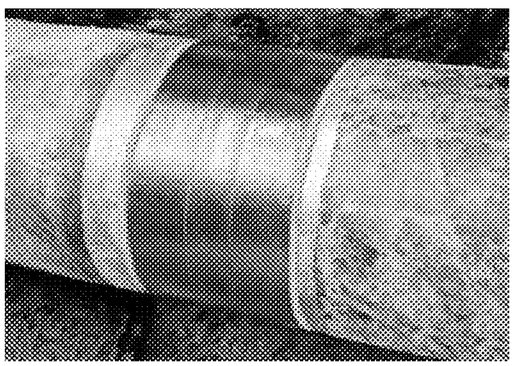

Figure K-6
Carbon Fiber Wrap Repair

K.2.6 Sprayed or Brushed Linings

Sprayed or brushed linings involve the use of high-strength adhesive or thermosetting resins that are applied to the inside surfaces of degraded piping. The resins are often used with reinforcing fibers, such as glass or carbon. The fibers may be applied as a cloth or chopped material. In certain cases the polymer is mixed with other constituents, such as ceramic particles, to provide enhanced erosion resistance, Figure K-7.

The repair requires a clean surface to obtain adequate adhesion.

The repair has limitations on operating temperatures due to limitations of the epoxy or resin.

The repair is permitted in Code Case N-589-1 (reference 98) but has not yet been approved by the NRC.

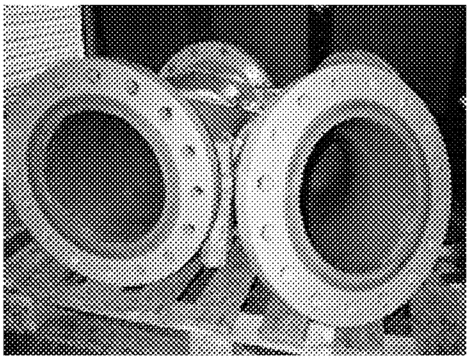

Figure K-7
Corroded Tee Repaired with Epoxy-Ceramic Lining

L
PREVENTION AND MITIGATION STRATEGIES

L.1 Water Treatment

One way to mitigate ID corrosion in water service is to chemically treat the water. Most plants treat the water with an oxidizing biocide, such as chlorine or bromine, using a continual low-dosing strategy. In most cases, no further treatment takes place downstream. However, the extent of accelerated corrosion and biofouling of plant equipment suggests that practices need to be reviewed and improved in order to improve reliability. This section is a summary of water treatment activities to reduce the likelihood of internal corrosion, as documented in references 14, 99 and 100.

L.1.1 Biocides

Biocides are often added to water for the control of macro-organisms (for example, clams, mussels, or barnacles) or micro-organisms (for example, bacteria, algae, or fungi). Their general characteristics are:

- They are effective against specific organisms.
- They are effective over a specific range of chemistry and temperature.
- They must be compatible with corrosion inhibitors.
- They must be inoculated in the right concentration and period.
- They are toxic and their use and discharge is limited within certain concentrations.
- Biocides are generally classified as oxidizing or nonoxidizing.

L.1.1.1 Oxidizing Biocides

- They include chlorine, hypochlorite, bromine and chlorine/bromine compounds including hydantoins, chlorine dioxide, hydrogen peroxide, and ozone.
- They oxidize living tissues and essentially "burn" organics.
- Organisms do not develop a resistance to oxidizing biocides.
- They can be effective at low concentrations.
- They are relatively inexpensive.
- They are oxidizers and can corrode the metal.

- They are consumed in oxidation reactions and may not persist at sufficiently high concentrations to achieve the desired effects everywhere in the system.
- They typically cannot penetrate established biofilms, tubercles, or other deposits, to inhibit the growth and reproduction of underlying anaerobic microorganisms.

L.1.1.2 Nonoxidizing Biocides

- They include sodium and potassium salts, DBPNA (2,2-dibromo-3-nitrilopropionamide), glutaraldehyde, quaternary amines, isothiazalone, and proprietary organics.
- They can destroy cell membranes or block specific metabolic effects.
- They are relatively more expensive and are used at higher concentrations than oxidizing biocides.
- They generally do not exacerbate corrosion.
- They will not be consumed by reactions with the pipe metal.
- They typically cannot penetrate established biofilms, tubercles, or other deposits, to inhibit the growth and reproduction of underlying anaerobic microorganisms.

L.1.2 Deposit Control Agents

- Deposit control agents include flocculants, surfactants, penetrants, and scale fluidizers
- They penetrate, soften or dissolve scale (precipitated dissolved solids) and foulants (settled suspended solids, mud, and so forth).
- The elimination of deposits mitigates crevice corrosion and MIC.
- Some can be combined with corrosion inhibitors or biocides.

L.1.3 Corrosion Inhibitors

Corrosion inhibitors can be classified on the basis of their action:

- Cathodic inhibitors affect the electrochemical corrosion resistance at the cathode. They include polyphosphates, zinc salts, and polysilicates.
- Anodic inhibitors affect the electrochemical corrosion resistance at the anode. They include chromates CrO_2 (toxic, no longer used), orthophosphates, nitrites NO_2, orthosilicates, and molybdates MoO_4 (copper pipe).
- Film inhibitors cause the corrosion film to become more protective. They include azoles.
- Antioxidants (closed cooling water systems) include hydrazine, carbohydrazide, DEHA, erythorbic acid, hydroquinone.
- Corrosion inhibitors for copper alloys include Tolyltriazole and Benzotriazole.

The action of corrosion inhibitors can take several forms:

- They may modify the nature of the corrosion product film to be a more protective film.
- They may promote further oxidation of the corrosion products to produce a more resistant film.
- They may incorporate other elements into the film (such as molybdenum) to produce a more protective corrosion product.
- They may form a barrier film that blocks the transport of metal ions away from the surface.
- They may stop cathodic reductants like oxygen from being reduced at the surface.

Cautions when including corrosion inhibitors (reference 100):

- Their effectiveness is a function of the alloy, and will be effective only over specific ranges of pH, temperature, flow, etc.
- They may interact with other chemicals that occur naturally or are added to the system, a factor that can further complicate treatment.
- Some corrosion inhibitors can serve as nutrients for bacteria and can lead to microbiological fouling and may lead to MIC.
- Decomposition products can produce corrosive species or provide nutrients for bacteria.
- Most chemical corrosion controls will only be effective when applied to clean metal surfaces, free of corrosion products, biofilms, scale, and other inorganic deposits.

L.2 Cleaning

The primary objective is generally to remove macrofouling, silt, and other deposits. Cleaning is recommended for several reasons (reference 101):

- Cleaning restores flow area and reduces the friction factor.
- It helps remove deposits that may produce localized corrosion.
- It prepares the surface for water treatment.
- It prepares the pipe for the application of a liner.

The degree of cleanliness is expressed in SSPC standards, in decreasing order of cleanliness:

- SSPC SP 5 (white metal, NACE No.1).
- SSPC SP 10 (near white).
- SSPC SP 6 (commercial, NACE No.3).
- SSPC SP 7 (brush off).

Field cleaning methods can in many cases achieve a NACE 1 SSPC 5 white metal finish. Cleaning can be achieved in various ways:

- Mechanical cleaning with brushes, scrapers, cleaning pigs (tethered or fluid driven where the pipeline size, components and layout permits), solid abrasive particles (sand blasting and sand jetting), air bubble pulsing.
- High-pressure water jets (hydrolazing, also referred to as hydro-blasting or hydro-lancing), or steam cleaning. Hydrolazing jets operate at pressures in the range of 2,000 psi to 12,000, and require careful planning.
- Chemical methods including inhibited mineral or organic acids and chelating agents (typically following mechanical or water jet cleaning).

Planning for cleaning operations includes:

- Selection of the cleaning method and its compatibility with the piping and components.
- Development of a cleaning procedure.
- Identification of access points.
- Isolating the system.
- Providing protective clothing to cleaning personnel.
- Providing personnel protection from cutting effects.
- Planning for confined space entry and radiological controls.
- Personnel training and performing a demonstration test.
- Determination of the required hose length.
- Protection of non-metallic trims, coatings and liners.
- System flush and inspection of effluents.
- Collection, storage and disposal of collected debris.
- Passivation of the cleaned surface.
- Dry or wet layup.

L.3 Coating

In order to reduce soil-side OD corrosion, it may be necessary to coat or re-coat the pipe, Figures L-1 to L-4. This retrofit should be considered in conjunction with installing (or restoring) a cathodic protection system since coating holidays, without cathodic protection, lead to accelerated pinhole leaks. Coating and CP go hand-in-hand. A thorough assessment of pipe coatings has been published in reference 50. Retrofit coatings are field applied and generally consist of tape wrap, coal-tar, cement-mortar, epoxy with a protective polyolefin jacket, and, for more localized repairs, sleeves. The applicable AWWA standards are listed for reference:

- C203-02: Coal-Tar Protective Coatings & Linings for Steel Water Pipelines, Enamel & Tape, Hot-Applied.
- C205-07: Cement-Mortar Protective Lining and Coating for Steel Water Pipe, 4 In. (100 mm) and Larger, Shop Applied.
- C209-06: Cold-Applied Tape Coatings for the Exterior of Special Sections, Connections, and Fittings for Steel Water Pipelines.
- C210-03: Liquid-Epoxy Coating Systems for the Interior and Exterior of Steel Water Pipelines.
- C213-01: Fusion-Bonded Epoxy Coating for the Interior and Exterior of Steel Water Pipelines.
- C214-07: Tape Coating Systems for the Exterior of Steel Water Pipelines.
- C215-04: Extruded Polyolefin Coatings for the Exterior of Steel Water Pipelines
- C216-07: Heat-Shrinkable Cross-Linked Polyolefin Coatings for the Exterior of Special Sections, Connections, and Fittings for Steel Water Pipelines.
- C217-04: Petrolatum and Petroleum Wax Tape Coatings for the Exterior of Connections and Fittings of Steel Water Pipelines.
- C218-02: Coating the Exterior of Aboveground Steel Water Pipelines and Fittings.
- C225-03: Fused Polyolefin Coating Systems for the Exterior of Steel Water Pipelines.

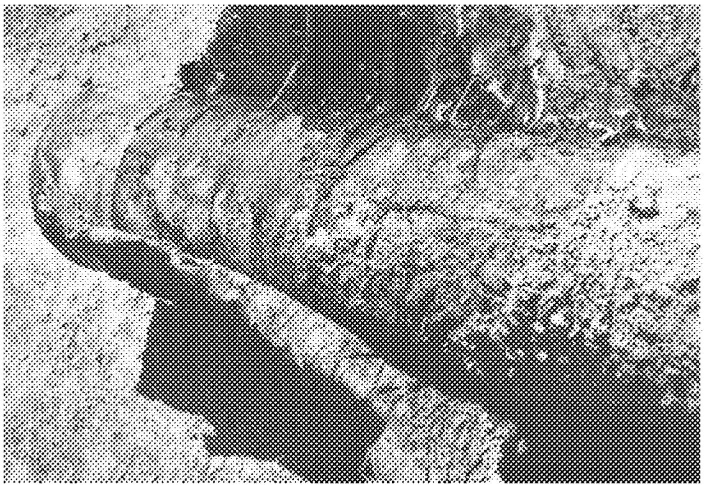

Figure L-1
Disbonded Tape Wrap

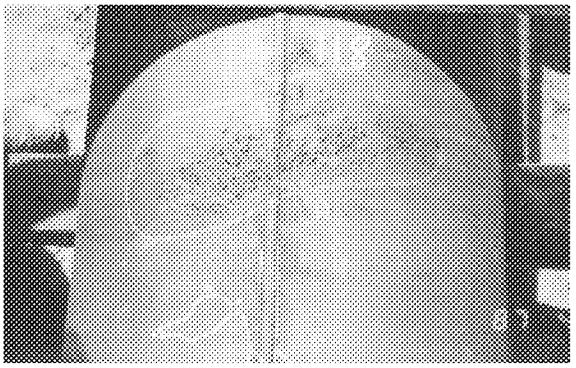

Figure L-2
Tenting Under Tape Wrap

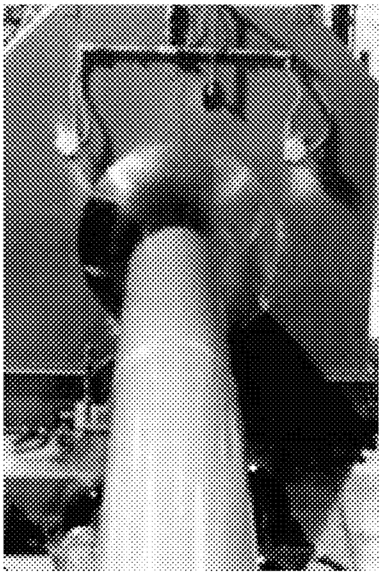

Figure L-3
Mill-Applied FBE Coating

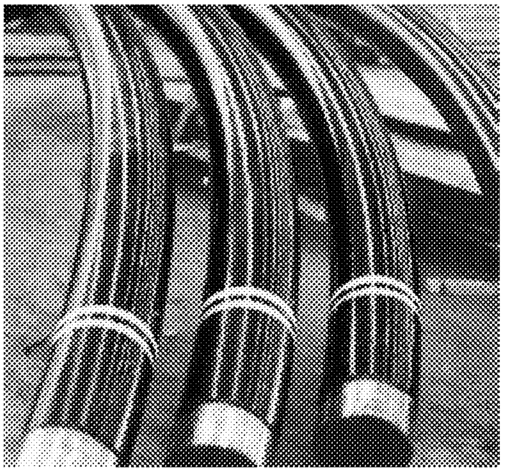

Figure L-4
Three-Layer Coating Epoxy-Adhesive-PE

L.4 Cathodic Protection

Cathodic protection (CP) consists in converting the buried pipe to be a cathode, either by

- Placing the pipe in electrical contact with a less noble metal (typically a sacrificial anode of zinc or magnesium), or
- Making current flow through the ground towards the pipe (impressed current).

The principles of CP are illustrated in Figure L-5 which shows both the sacrificial anode as well as the impressed current system. CP is addressed in detail in specialized publications, including references 26, 31, and 102 to 104.

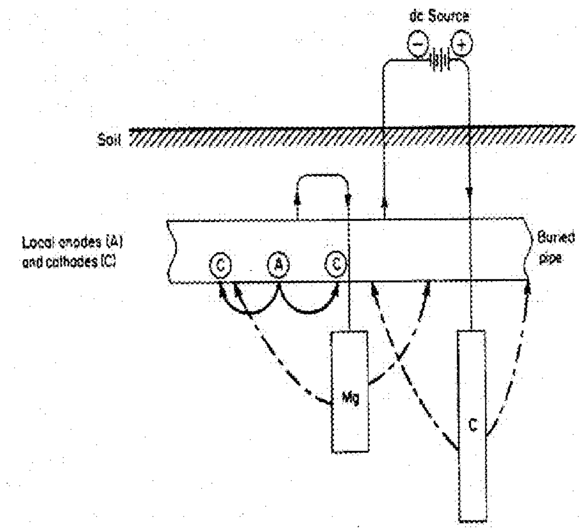

Figure L-5
The Two Types of CP Systems

For oil and gas transmission pipelines, cathodic protection is consistently applied and scrupulously well maintained. The CP systems are sized, designed, installed, and periodically inspected and tested to make sure they provide the right protection. In the pipeline world, the CP system is a production necessity, as well as a regulatory mandate. Excerpts of Code and Regulations for liquid hydrocarbon pipelines are presented here for information:

ASME Code for liquid pipelines ASME B31.4

"Control of external corrosion of buried or submerged pipe and components in new installations (including new pump stations, tank farms, and terminals, and relocating, replacing, or otherwise changing existing piping systems) shall be accomplished by the application of an effective protective coating supplemented with cathodic protection and suitable drainage bonds in stray current areas.

Cathodic protection facilities for new or existing piping systems shall be maintained in a serviceable condition, and electrical measurements and inspections of cathodically protected buried or submerged piping systems, including tests for stray electrical currents, shall be conducted at least each calendar year, but with intervals not exceeding 15 months".

Pipelines Regulation 49CFR195, Subpart H Corrosion Control Sec. 195.573

"(1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

(2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169 (incorporated by reference, see Sec. 195.3).

In process and power plants, the design and maintenance of CP systems is complicated by the fact that the ground is quite congested compared to the right-of-way of an oil or gas pipeline, and electrical interferences are common. Still, CP systems can be designed and maintained in most cases even in a congested environment (reference 102)."

L.5 Internal Lining

Linings are applied to the pipe inner diameter to prevent corrosion of the pipe by the fluid, Figure L-6. Two large categories of liners include insertion liners (addressed in Appendix K) and sprayed or brushed form. When pipe entry is feasible, linings can be applied by brush or spray. Where pipe entry is not feasible, linings can be applied by remote controlled crawlers with rotating spray heads. As in the case of coatings, surface cleanliness and surface finish are essential. Common lining systems used in power plants include:

- Solvent-free epoxy system: primer, intermediate coat, topcoat.
- Elastomeric materials such as PVC or vulcanized rubber.
- Cementious.
- Polyethylene.
- Fiberglass reinforced linings.

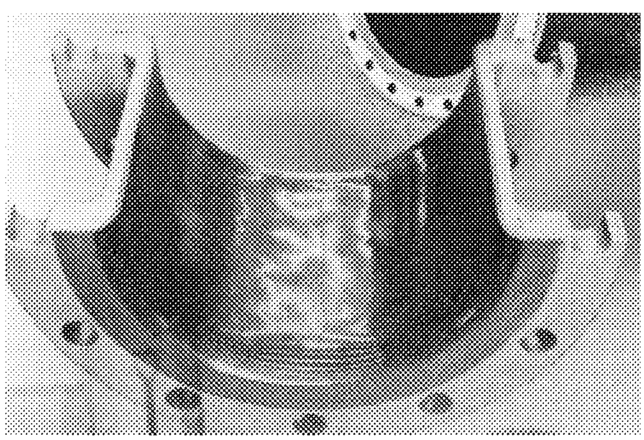

Figure L-6
Corrosion Resistance Liner

L.6 Alternate Materials

A degraded buried pipe may be replaced by a different, more corrosion resistant material. The new material may be metallic or non-metallic.

L.6.1 Metallic Pipe Replacement

Although corrosion rates for various metals vary greatly depending on the soil and particular alloys and degree of cold working of the metal, general trends are reported based on soil corrosion studies.

Cast Iron. Cast iron with 2.5% C, 1.4% Si and 0.3% Mn performed better than low carbon steel after five years of exposure to clay soil. The pit depth corresponded to 12 mils per year (mpy) for cast iron compared to 20 mpy for low carbon steel (reference 22).

Bare Carbon Steel. The corrosion rate of bare carbon steel in soil, without cathodic protection, can range from less than 1 mpy in favorable conditions, to 20 mpy or more in aggressive soils.

Galvanized Carbon Steel. Once corrosion has punctured the Zn coating, the iron beneath is cathodically protected. Thus, galvanized carbon steel may corrode at less than 0.2 mpy in mild conditions to 1 mpy or more in unfavorable soils. By measuring the corrosion rates in a particular soil, it is possible to install galvanized steel with a corrosion allowance over-thickness to obtain the desired design life.

Austenitic Stainless Steel. Austenitic stainless steels performed better than cast iron in clay soil. The pit depth corresponded to less than 0.5 mpy for 18-8 austenitic stainless steel.

Super-Austenitic Steels. AL-6XN® (by Allegheny Ludlum) is a super-austenitic alloy (20% Cr - 24% Ni – 6.3%Mo – 0.22% N), designed to resist crevice corrosion, pitting, chloride-induced corrosion, and stress corrosion cracking. It can also withstand alkaline and salt solutions, protecting against metallic contamination.

Copper. Copper alloys containing zinc (brass 66% Cu + 33% Zn, and Cu-Ni-Zn alloys) generally experience dezincification within ten years of burial. Copper alloys without Zn perform well, with a corrosion rate in the range of 1 mpy (reference 22).

L.6.2 Non-Metallic Pipe Replacement

High Density Polyethylene (HDPE) is ideally suited for buried pipe applications at ambient temperatures, which explains its use as the preferred material for buried waterworks and gas distribution pipe applications. It is joined using heat fusion techniques with specialized equipment. ASME, EPRI and others have performed a significant amount of work to gain ASME Code acceptance of HDPE as a material for buried pipe, safety as well as non-safety-related applications (references 105 to 108). Fiber-reinforced plastic pipe (FRP) is also a commonly used material for buried pipe applications.

L.7 Special Trench Fill

Since soil corrosion is dependent on the soil corrosivity and hence its humidity, specially engineered hydrophobic fills have been developed and are used to protect buried metallic pipes. One such example is Gilsulate (reference 109), Figure L-7. It is a hydrophobic granular fill that prevents underground water from intruding onto the pipe and has a resistivity greater than 10^{12} ohm-centimeters (Ω.cm). It has been used successfully, without cathodic protection, to prevent soil-side OD corrosion in bare carbon steel buried pipe.

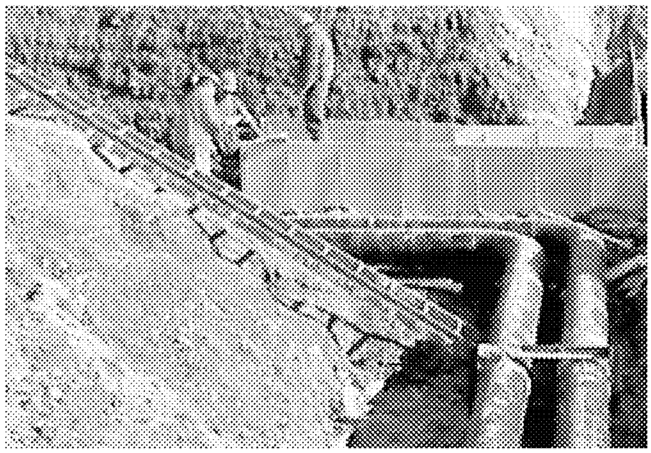

Figure L-7
Installation of Gilsulate® Fill around Pipe

L.8 On-Line Leak Detection

The repair techniques in Chapter 5 addressed methods used to locate the source of a leak. This section reviews automated on-line leak detection methods which would permit automated alarm, and quick response to isolate and mitigate a leak.

Monitoring Wells. Monitoring wells with detection devices can be used to detect underground leaks. Their efficiency in the case of buried pipe leaks depends on the distance to the pipe, the geology, and the leak rate and content.

Acoustic Signal. Permanently installed acoustic instruments are used to detect leaks in underground tanks and pipelines, both aboveground and buried, by comparing the noise signal of the leak with background noise during normal flow without a leak.

Cable Resistance. A low current is circulated through a cable buried near the pipe. A liquid leak is detected as a short in the cable.

Permeable Vacuum Tube. Air is constantly drawn out from a permeable tube buried next to the pipeline. In case of a fuel oil or lube oil leak, an alarm indicates the presence of oil vapors drawn into the tube.

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